

US Patent & Trademark Office

Patent Public Search | Text View

United States Patent	12392925
Kind Code	B2
Date of Patent	August 19, 2025
Inventor(s)	Chen; Hsieh et al.

Waterflood front imaging using segmentally insulated well liners as on-demand electrodes

Abstract

A method for monitoring waterfront movement in a subsurface formation involves performing forward modeling of at least one deep electromagnetic survey of the waterfront movement, and determining locations for installing an electrically insulating spacer between well liners to form an on-demand electromagnetic source electrode. Based on the forward modeling, repeat survey time intervals are predicted. The method involves, during well completion, installing the electrically insulating spacer between the well liners in a reservoir to form at least one on-demand electromagnetic source electrode, and installing the electrically insulating spacer between the plurality of well liners in a reservoir to form an on-demand electromagnetic receiver electrode. A waterfront survey is performed by conveying a production logging tool into a well that temporarily converts the well liners into an on-demand electromagnetic source electrode and an on-demand receiver electrode, and inverse modeling of the waterfront survey is performed to produce a water saturation image.

Inventors:	Chen; Hsieh (Cambridge, MA), Poitzsch; Martin E. (Cambridge, MA)
Applicant:	SAUDI ARABIAN OIL COMPANY (Dhahran, SA)
Family ID:	1000008765478
Assignee:	SAUDI ARABIAN OIL COMPANY (Dhahran, SA)
Appl. No.:	18/592215
Filed:	February 29, 2024

Prior Publication Data

Document Identifier	Publication Date
US 20240255674 A1	Aug. 01, 2024

Related U.S. Application Data

Publication Classification

Int. Cl.: **G01V20/00** (20240101); **E21B43/08** (20060101); **E21B47/002** (20120101); **E21B47/113** (20120101); **G01V3/26** (20060101); **G01V3/38** (20060101); **G06F30/20** (20200101); **G06F111/10** (20200101); **G06F113/08** (20200101)

U.S. Cl.:

CPC **G01V20/00** (20240101); **E21B43/08** (20130101); **E21B47/0025** (20200501); **E21B47/113** (20200501); **G01V3/26** (20130101); **G01V3/38** (20130101); **G06F30/20** (20200101); **E21B2200/20** (20200501); **G06F2111/10** (20200101); **G06F2113/08** (20200101)

Field of Classification Search

CPC: G01V (3/38); G01V (3/26); G06F (30/20); E21B (47/0025); E21B (47/113); E21B (43/08)

USPC: 703/10

References Cited

U.S. PATENT DOCUMENTS

Patent No.	Issued Date	Patentee Name	U.S. Cl.	CPC
5233304	12/1992	Hubans	324/333	G01V 3/28
6667621	12/2002	Benimeli	324/347	G01V 3/20
6672385	12/2003	Kilaas	166/228	E21B 43/082
6778918	12/2003	Delhomme	702/50	E21B 47/10
6868906	12/2004	Vail, III	166/250.15	E21B 43/103
7909097	12/2010	Ayasse	166/371	E21B 43/243
8079416	12/2010	Parker	166/376	E21B 43/11
8392119	12/2012	Alumbaugh	702/7	G01V 3/38
8638103	12/2013	Rosthal	324/365	G01V 3/30
8901931	12/2013	Esmersoy	324/338	G01V 3/28
8931570	12/2014	Casciaro	166/373	E21B 34/08
9739905	12/2016	Sena	N/A	G01V 3/30
9938822	12/2017	Fouda	N/A	G01V 3/18
9951568	12/2017	Brown	N/A	E21B 43/10
10267943	12/2018	Marsala	N/A	G01V 3/38
2002/0059048	12/2001	Hardy	703/10	E21B 49/006
2003/0220750	12/2002	Delhomme	702/50	E21B 43/20
2008/0238428	12/2007	Babour	324/323	G01V 3/083
2009/0005994	12/2008	Srnka	702/7	G01V 3/12
2009/0150124	12/2008	Wilt	703/1	G01V 99/00
2010/0259268	12/2009	Zhang	324/339	G01V 3/28
2011/0036569	12/2010	Bass	166/250.16	G01V 3/28
2011/0166840	12/2010	Green	703/2	G01V 3/38

2011/0308789	12/2010	Zhang	166/66.5	G01V 3/28
2012/0130641	12/2011	Morrison	702/7	G01V 3/26
2012/0191353	12/2011	Wilt	702/6	G06F 30/23
2012/0293179	12/2011	Colombo	324/339	G01V 3/26
2014/0019051	12/2013	Brady	702/7	G01V 3/38
2014/0036628	12/2013	Hill	367/35	G01V 1/42
2014/0167767	12/2013	Herrera	324/339	G01V 3/24
2014/0222343	12/2013	Samson	702/8	G01V 3/12
2015/0061684	12/2014	Marsala	324/355	E21B 49/00
2015/0083404	12/2014	Wilt	166/250.1	E21B 47/092
2015/0101817	12/2014	White	175/45	E21B 7/046
2015/0369949	12/2014	Cuevas	324/338	G01V 3/26
2016/0003962	12/2015	Sena	324/339	E21B 47/092
2016/0266269	12/2015	Wilson	N/A	G01V 3/108
2016/0282502	12/2015	Sharma	N/A	G01V 3/30
2016/0290124	12/2015	Chemali	N/A	E21B 47/113
2016/0320515	12/2015	Clark	N/A	G01V 3/20
2017/0082770	12/2016	Mandviwala	N/A	E21B 47/12
2017/0138132	12/2016	Wilson	N/A	E21B 49/00
2017/0284190	12/2016	Dashevsky	N/A	E21B 49/08
2017/0292367	12/2016	Fouda	N/A	E21B 47/113
2018/0128097	12/2017	DePavia	N/A	E21B 47/13
2018/0203154	12/2017	Gabelmann et al.	N/A	N/A
2018/0223654	12/2017	Roberson	N/A	E21B 47/16
2018/0231681	12/2017	Katterbauer	N/A	G01V 3/36
2018/0259672	12/2017	Samson	N/A	G01V 3/28
2018/0283168	12/2017	Ranjan	N/A	G01V 3/26
2019/0196039	12/2018	Wilson	N/A	G01V 3/30
2019/0271793	12/2018	Wilson	N/A	G01V 3/38
2020/0319365	12/2019	Colombo	N/A	G01V 3/088
2020/0348440	12/2019	Cancelliere	N/A	G01V 5/26
2020/0363554	12/2019	Colombo	N/A	E21B 43/20
2021/0140307	12/2020	McNeice	N/A	E21B 47/13
2022/0099859	12/2021	Chen	N/A	G01V 3/30

OTHER PUBLICATIONS

Anthony G. Nekut (“Crosswell electromagnetic tomography in steel-cased wells”, Geophysics, vol. 60, No. 3 (May-Jun. 1995) ; p. 912-920) (Year: 1995). cited by examiner

Colombo et al. (“Quantifying surface-to-reservoir electromagnetics for waterflood monitoring in a Saudi Arabian carbonate reservoir”, Geophysics, vol. 78, No. 6 (Nov.-Dec. 2013); p. E281-E297) (Year: 2013). cited by examiner

Sena et al. (Borehole Electromagnetic Technique for Reservoir Imaging and Monitoring from Uncased Sections of a Well Using Adjacent Casings as Receiver Antennas, 2019, International Petroleum Technology Conference, pp. 1-7) (Year: 2019). cited by examiner

Shantsev et al. (Time-lapse CSEM: how important is survey repeatability, 2020, Geophys. J. Int. pp. 2133-2147) (Year: 2020). cited by examiner

Non-Final office action issued by the U.S. Patent Office for corresponding U.S. Appl. No. 18/325,731, mailed Aug. 19, 2024 (14 pages). cited by applicant

Background/Summary

(1) This Application is a Divisional of application Ser. No. 17/038,345 filed on Sep. 30, 2020. The entire contents of these applications are incorporated herein by reference in their entirety.

BACKGROUND

(1) Hydrocarbon resources are often located below the earth's surface, sometimes tens of thousands of feet below the surface. In order to extract hydrocarbon fluids, that is, oil and/or gas, wells may be drilled to gain access to reservoirs found in subterranean porous rock formations. Wells may be drilled vertically into the earth or deviated from vertical, even up to horizontal in order to most effectively and efficiently access subsurface hydrocarbon reservoirs.

(2) Wells may be cased to protect the integrity of the well and the surrounding formations through which the wellbore may pass. Casing may be fixed in place by injecting cement into the annulus between the casing and the surrounding formation. Casing may be conductive, for example, the casing may be made of some form of metal, particularly a form of steel. Less frequently, non-conductive casing may be used as well.

(3) During the productive lifetime of an oil well (hereinafter, oil well is understood to include any well that used in the production of hydrocarbon fluids), subsurface water may move toward a producing well. In some cases, this may occur naturally, while in other cases, water may be injected into one or more neighboring wells to drive the hydrocarbon fluids in the reservoir toward the producing well. Accurately monitoring the waterflood front may provide valuable information in optimizing well productivity.

(4) Deep electromagnetic (EM) surveys have long been of great interest for oil companies as a means to monitor waterflood fronts. EM surveys have provided invaluable information for reservoir-scale saturation mapping with unprecedented details. However, when conducted on existing wells, there may be some limitations for the EM surveys. For example, dedicated EM transmitters and receivers used for EM surveys may be thicker and longer than conventional logging tools, which may increase the difficulty for their conveyance for downhole surveys. Further, typical data acquisition time for these EM surveys may range from multiple days to weeks, resulting in downtimes for normal field operations and costs associated with the downtime. In addition, metal casings may greatly attenuate the EM sensitivity, which may limit which wells may be selected for monitoring.

(5) Downhole permanent electrode arrays may offer the possibility of long-term continuous monitoring of adjacent water movements to aid in reservoir management. However, extremely high upfront cost for installation of downhole permanent electrode arrays as well as suboptimal reliability for the downhole sensors has limited their applicability.

SUMMARY

(6) In general, in one aspect, embodiments disclosed herein relate to a method for monitoring waterfront movement in a subsurface formation, the method includes: performing forward modeling of at least one deep electromagnetic survey of the waterfront movement: determining, based on the forward modeling, locations for installing at least one electrically insulating spacer between a plurality of well liners to form at least one on-demand electromagnetic source electrode: predicting, based on the forward modeling, repeat survey time intervals: during well completion, installing the at least one electrically insulating spacer between the plurality of well liners in a reservoir to form at least one on-demand electromagnetic source electrode: during well completion,

installing the at least one electrically insulating spacer between the plurality of well liners in a reservoir to form at least one on-demand electromagnetic receiver electrode: electromagnetically performing a waterfront survey by conveying into a well at least one production logging tool that temporarily converts the plurality of well liners into at least one on-demand electromagnetic source electrode and at least one on-demand receiver electrode: performing inverse modeling of the waterfront survey: and producing, based the inverse modeling, a water saturation image.

(7) In general, in one aspect, embodiments disclosed herein relate to a system for monitoring waterfront movement in a subsurface formation, the system including: a plurality of well liners disposed in at least one well. Each well liner includes an electrically conductive material having a shape of a hollow cylinder: at least one electrically insulating spacer disposed between two of the plurality of well liners to form at least one on-demand electromagnetic source electrode: at least one electrically insulating spacer disposed between two of the plurality of well liners to form at least one on-demand electromagnetic receiver electrode: a well logging tool including: a cylindrical housing having an outer diameter less than an inner diameter of the hollow cylinder: a plurality of insulated centralizers disposed around the cylindrical housing: a plurality of electrical connections that selectively connect to at least one of the plurality of well liners: a power connection that receives power from a surface location, and a communication connection that communicates with the surface location: and a conveyor that disposes the well logging tool within the plurality of well liners.

Description

BRIEF DESCRIPTION OF DRAWINGS

(1) The following is a description of the figures in the accompanying drawings. In the drawings, identical reference numbers identify similar elements or acts. The sizes and relative positions of elements in the drawings are not necessarily drawn to scale. For example, the shapes of various elements and angles are not necessarily drawn to scale, and some of these elements may be arbitrarily enlarged and positioned to improve drawing legibility. Further, the particular shapes of the elements as drawn are not necessarily intended to convey any information regarding the actual shape of the particular elements and have been solely selected for ease of recognition in the drawing.

(2) FIG. 1 is a schematic diagram of an exemplary well site in accordance with one or more embodiments.

(3) FIG. 2 is a schematic diagram of a downhole permanent electrode array.

(4) FIG. 3 is a flowchart describing a method in accordance with one or more embodiments.

(5) FIGS. 4A-4D are schematic diagrams of a workflow in accordance with one or more embodiments.

(6) FIG. 5A is a schematic diagram of a contemporary field with complex horizontal wells in accordance with one or more embodiments.

(7) FIG. 5B is a schematic diagram of a simulated domain containing two well liners with each well liner consisted of four conducting segments separated by insulators in accordance with one or more embodiments.

(8) FIGS. 6A and 6B represent potential and current density fields, respectively, calculated from finite element analysis in accordance with one or more embodiments.

(9) FIG. 7A shows current flowed into an electrode (top) and normalized current changes (bottom) as a function of waterfront-to-electrode distance for various reservoir resistivities in accordance with one or more embodiments.

(10) FIG. 7B shows current flowed into an electrode (top) and normalized current changes (bottom) as a function of waterfront-to-electrode distance for various waterfront resistivities in accordance

with one or more embodiments.

(11) FIG. 8A shows current flowed into an electrode (top) and normalized current changes (bottom) as a function of waterfront-to-electrode distance for various electrode distances in accordance with one or more embodiments.

(12) FIG. 8B shows current flowed into an electrode (top) and normalized current changes (bottom) as a function of waterfront-to-electrode distance for various reservoir thicknesses in accordance with one or more embodiments.

(13) FIG. 9A is a schematic diagram of representative electrode geometry with the presence of neighboring electrodes in accordance with one or more embodiments.

(14) FIG. 9B shows current flowed into an electrode (top) and normalized current changes (bottom) as a function of waterfront-to-electrode distance for various neighboring electrode distances in accordance with one or more embodiments.

(15) FIG. 10 shows a computer system in accordance with one or more embodiments.

DETAILED DESCRIPTION

(16) In the following detailed description, certain specific details are set forth in order to provide a thorough understanding of various disclosed implementations and embodiments. However, one skilled in the relevant art will recognize that implementations and embodiments may be practiced without one or more of these specific details, or with other methods, components, materials, and so forth. In other instances, well known features or processes associated with hydrocarbon production systems have not been shown or described in detail to avoid unnecessarily obscuring descriptions of the implementations and embodiments. For the sake of continuity, and in the interest of conciseness, same or similar reference characters may be used for same or similar objects in multiple figures.

(17) Throughout the application, ordinal numbers (e.g., first, second, third, etc.) may be used as an adjective for an element (i.e., any noun in the application). The use of ordinal numbers is not to imply or create any particular ordering of the elements nor to limit any element to being only a single element unless expressly disclosed, such as using the terms “before”, “after”, “single”, and other such terminology. Rather, the use of ordinal numbers is to distinguish between the elements. By way of an example, a first element is distinct from a second element, and the first element may encompass more than one element and succeed (or precede) the second element in an ordering of elements.

(18) A deviated well, as used herein, describes a well whose wellbore is not vertical. A horizontal well is a special case of a deviated well in which the wellbore is essentially horizontal, but may deviate from the vertical by at least 80 degrees. A horizontal well may stay in a hydrocarbon reservoir for a greater length of the reservoir, allowing greater hydrocarbon production from the well.

(19) A screen, or sand screen, or wire-wrapped screen, as used herein, refers to a device used to control formation sand from entering production tubing used to bring hydrocarbon fluids to the surface. A screen may include a perforated liner with perforations shaped as elongated slots or round holes. The dimensions of the screen and its components may be varied to suit the reservoir conditions.

(20) As used herein, a logging unit, for example, a production logging unit, is where a logging engineer may control and monitor a well logging operation. A logging unit may contain such instruments as a data recorder, a depth recording system, and a winch.

(21) In this disclosure, the terms well, oil well, gas well, oil and gas well, and like terms may be used interchangeably without narrowing the type of well unless specifically stated.

(22) Regarding directions of a coordinate system, the axial direction may be a direction parallel to an axis of rotation. In a well, the axial direction may be the direction parallel to the wellbore and may be local. That is, if the wellbore changes direction along its length, one may still refer to an axial direction at any point along the wellbore as being tangential to the direction of the wellbore at

that location. The radial direction is perpendicular to the axial direction and points along a radius away from the axis. The azimuthal direction is perpendicular to the axial and the radial directions.

(23) A fluid is a material that is capable of flowing. Thus, both liquids and gases are fluids. In oil and gas wells, oil, gas, and water are examples of fluids that may be encountered.

(24) FIG. 1 illustrates an exemplary well site **100**. In general, well sites may be configured in a myriad of ways. Therefore, well site **100** is not intended to be limiting with respect to the particular configuration of the drilling equipment. Well site **100** is depicted as being on land. In other examples, well site **100** may be offshore, and drilling may be carried out with or without use of a marine riser. A drilling operation at well site **100** may include drilling a wellbore **102** into a subsurface including various formations, such as formations **104**, **106**. For the purpose of drilling a new section of wellbore **102**, a drill string **108** is suspended within wellbore **102**. Drill string **108** may include one or more drill pipes **109** connected to form conduit and a bottom hole assembly (BHA) **110** disposed at the distal end of the conduit. The BHA **110** may include a drill bit **112** to cut into the subsurface rock. The BHA **110** may include measurement tools, such as a measurement-while-drilling (MWD) tool **114** and logging-while-drilling (LWD) tool **116**. Measurement tools **114**, **116** may include sensors and hardware to measure downhole drilling parameters, and these measurements may be transmitted to the surface using any suitable telemetry system known in the art. The BHA **110** and drill string **108** may include other drilling tools known in the art but not specifically shown.

(25) Drill string **108** may be suspended in wellbore **102** by a derrick **118**. A crown block **120** may be mounted at the top of derrick **118**, and a traveling block **122** may hang down from crown block **120** by means of a cable or drilling line **124**. One end of cable **124** may be connected to a drawworks **126**, which is a reeling device that can be used to adjust the length of cable **124** so that traveling block **122** moves up or down derrick **118**. Traveling block **122** may include a hook **128** on which a top drive **130** is supported. Top drive **130** is coupled to the top of drill string **108** and is operable to rotate drill string **108**. Alternatively, drill string **108** may be rotated by means of a rotary table (not shown) on the drilling floor **131**. Drilling fluid (commonly called mud) may be stored in a pit (mud pit) **132**, and at least one pump **134** may pump the mud from pit **132** into drill string **108**. The mud may flow into drill string **108** through appropriate flow paths in top drive **130** (or a rotary swivel if a rotary table is used instead of a top drive to rotate drill string **108**).

(26) In one implementation, a system **200** may be disposed at or communicate with well site **100**. System **200** may control at least a portion of a drilling operation at well site **100** by providing controls to various components of the drilling operation. In one or more embodiments, system **200** may receive data from one or more sensors **160** arranged to measure controllable parameters of the drilling operation. As a non-limiting example, sensors **160** may be arranged to measure WOB (weight on bit), RPM (drill string rotational speed), GPM (flow rate of the mud pumps), and ROP (rate of penetration of the drilling operation). Sensors **160** may be positioned to measure parameter(s) related to rotation of drill string **108**, parameter(s) related to travel of the traveling block **122**, which may be used to determine ROP of the drilling operation, and parameter(s) related to flow rate of pump **134**. For illustration purposes, sensors **160** are shown on drill string **108** and proximate mud pump **134**. The illustrated locations of sensors **160** are not intended to be limiting, and sensors **160** could be disposed wherever drilling parameters need to be measured. Moreover, there may be many more sensors **160** than shown in FIG. 1 to measure various other parameters of the drilling operation. Each sensor **160** may be configured to measure a desired physical stimulus.

(27) During a drilling operation at well site **100**, drill string **108** is rotated relative to wellbore **102**, and weight is applied to drill bit **112** to enable drill bit **112** to break rock as drill string **108** is rotated. In some cases, drill bit **112** may be rotated independently with a drilling motor. While cutting rock with drill bit **112**, mud is pumped into drill string **108**. The mud flows down drill string **108** and exits into the bottom of wellbore **102** through nozzles in drill bit **112**. The mud in wellbore **102** then flows back up to the surface in an annular space between drill string **108** and wellbore **102**

with entrained cuttings. The mud with the cuttings is returned to pit **132** to be circulated back again into drill string **108**. Typically, the cuttings are removed from the mud, and the mud is reconditioned as necessary, before pumping the mud again into drill string **108**. In one or more embodiments, the drilling operation may be controlled by system **200**.

(28) Referring now to FIG. **2**, a drilling rig **210** may be erected on a surface **220** for the purpose of drilling a well, particularly a well for the production of hydrocarbon fluids that may be contained in a subterranean porous rock formation, or reservoir. The surface **220** may be the earth's surface if the drilling rig **210** is a land rig. If the drilling location is offshore, the surface **220** may be on a drill ship, an offshore platform, or the like. The well may be deviated, and in particular, may be horizontal **230** in order to maintain the well in the hydrocarbon reservoir over an extended distance. Permanent downhole electrodes **240** may be installed to monitor a waterflood front by providing a deep electromagnetic (EM) survey. However, such installations may be too expensive for some applications.

(29) Some wells may be completed with metallic casing which may be inserted into the well and cemented into place. However it is common practice, particularly in hydrocarbon reservoirs in strong, rigid (competent) reservoir rocks including, but not limited to, carbonate reservoir rocks, to use openhole, or barefoot, completions for many wells. In openhole completions no casing is used. Instead, an uncemented metallic liner may be inserted into the well and may act as a conduit through which hydrocarbon fluids may flow to the surface. The portion of the liner that traverses the hydrocarbon reservoir may include slots through which fluids may flow from the reservoir into the production conduit. The portion of the liner that traverses the hydrocarbon reservoir may include a sand-screen that prevents solid particles, such as sand, from entering the production conduit.

(30) In one or more embodiments, a method for monitoring waterfront movement in a subsurface formation from a well with an openhole completion may include a deep EM survey using well liners segmentally insulated with nonconductive spacers, that is, insulating spacers, and production logging (PL) tools. This method may include the installation of passive insulators, or spacers, between well liners, or well liner segments, in a way that produces minimum interference with well completion processes and much lower failure rates compared to the installation of permanent active downhole sensors. The upfront hardware required in one or more embodiments may include, without limitation, a plurality of insulated spacers to electrically isolate a plurality of electrically conducting (metallic) liner segments. In one or more embodiments, the insulated spacers may be constructed from ceramic, or thermoplastic materials, or other electrically insulating materials. In accordance with one or more embodiments, the number of insulated spacers may be small, for example five or fewer, thus the upfront hardware cost may be negligible, particularly when compared to permanent active downhole sensors.

(31) Further, the conveyance of a PL tool to convert the well liners into EM electrodes may be simpler, less costly, more versatile, and more sensitive compared to the conveyance of dedicated EM transmitters and receivers in existing completed wells. In addition, the conveyance of the PL tool could potentially be accomplished with wireline cased-hole tractors, which may be much less costly than using coiled tubing conveyance. Tough Logging Conditions (TLC) conveyance may also be used.

(32) Further still, the method according to one or more embodiments may be applicable to openhole, or barefoot, completions, where no casing is used in the wellbore so that produced hydrocarbon fluids flow directly into the wellbore, and thence through a liner, which may be equipped with a sand-screen into the production conduit.

(33) Referring now to FIG. **3**, in one or more embodiments, the method for monitoring waterfront movement in a subsurface formation includes, considering the wells development plan for the field, performing forward modeling of at least one deep EM survey of the waterfront movement (**S310**) to select wells in which to install insulating spacers between metal well liners or well liner

segments and to predict time intervals at which the deep EM survey needs to be repeated (S330).

(34) Forward modeling of a deep EM survey includes, in one or more embodiments, solving a coupled system comprising Maxwell's equations and the constitutive equations for the rock formations using an assumed spatial distribution of resistivity and permittivity within the reservoir. The voltages and currents applied to the source electrodes are used as boundary conditions. The solution of the coupled system may in some embodiments involve the application of a finite-difference, or a finite-element algorithm to predict the EM fields detected by the receiver electrodes. In accordance, the solution of the coupled system may be achieved in the time-domain or in the frequency domain.

(35) In other embodiments, particularly when the spatial distribution of resistivity and permittivity within the reservoir is highly symmetric, for example, layered or homogeneous, Maxwell's equations and the constitutive equations may be simplified, and solved analytically or quasi-analytically.

(36) The method may also include determining, based on the forward modeling, locations for installing at least one electrically insulating spacer between selected well liners of a plurality of well liners in a reservoir under development during well completion (S320) and installing the spacers in those locations (S340).

(37) The method may include performing the deep EM survey by conveying specially designed PL tools into wells so that the PL tools may temporarily convert the segmentally insulated well liners into on-demand EM electrodes (sources and receivers) and establish a baseline measurement (S350).

(38) In one or more embodiments, the method may include performing repeated surveys and evaluating measurement changes over time. The method may also include estimating the proximity of a waterfront or other conductivity discontinuity by comparison with forward modeling.

(39) The method may include performing inverse modeling (S360) and, based on the inverse modeling, producing 2D and/or 3D water saturation images (S370). In contrast to forward modeling which predicts an EM field at a receiver electrode from known source electrode voltages and currents, and an assumed spatial distribution of resistivity and permittivity within the reservoir, inverse modeling predicts the spatial distribution of resistivity and permittivity within the reservoir given the measured EM fields at the receiver electrodes and the known source electrode voltages and currents. In some embodiments, inverse modeling is achieved by iteratively performing forward modeling and comparing the predicted values of the EM field at the receiver electrode with the measured value and adjusting the assumed spatial distribution of resistivity and permittivity within the reservoir to obtain a better match between the predicted and measured values.

(40) The method may also optimize the deep EM survey based on observed waterfront movements, costs, and other reservoir characteristics. For example, the optimum survey design may depend, without limitation, on well spacings, well path trajectories, reservoir thickness and uniformity, resistivity contrast between waterflood front and reservoir, and resistivity contrast between reservoir, and caprock, and basement strata.

(41) Some of the details of the workflow may be seen by referring to FIG. 4A. FIG. 4A shows a schematic of a contemporary reservoir with multiple horizontal wells **404**, **405**, **406**, **407** and a waterfront **403** that forms the boundary between water **401** and oil **402** in the reservoir. During hydrocarbon fluid production, the waterfront **403** may approach production wells **404**, **405**, **406**, **407**. Forward modeling may be used to predict the response of EM surveys and to select positions to place electrically insulating spacers, represented as lines crossing the wells in FIG. 4A, between well liners or well liner segments. The insulating spacers may be put at the end of wells nearest to the waterfront **408**, **409**. However, the insulating spacers may be put in other places for potential later use **410**, **411**, **412**, **413**, **414**.

(42) The distances between insulated well liner segments on different wells (e.g., **408** to **409**) may range from 100 to 1000 meters. The distances between insulated well liner segments to waterfront

(e.g., **409** to **403**) may also range from 100 to 1000 meters.

(43) With typical waterfront movement of approximately 1 foot per day (ft/day) (about 110 meters/year), the EM surveys may be performed once or twice a year.

(44) FIG. **4B** shows a part of an open hole well with liners **422**, **423** segmentally separated by insulating spacers **424**, **425**, **426** in reservoir formation **421** according to one or more embodiments. The metal liners **422**, **423** may be steel tubes about 40 ft in length and 4½ inches in diameter. According to one or more embodiments, nonmetallic, insulating spacers **424**, **425**, **426**, such as ceramics or thermoplastics, may be used to connect well liners so that individual well liners can act as electrodes separately. Note conventionally the well liners are connected with metal-on-metal connections, which would not work in these embodiments because with metal connections all well liners would be electrically shorted together and could not be converted to electrodes segmentally. The lengths of the spacers **424**, **425**, **426** may be less than 10 inches with diameters slightly larger than the diameters of the well liners.

(45) FIG. **4C** shows a PL tool **441** designed especially for one or more embodiments. The PL tool **441** may comprise insulated centralizers **442**, **443**. In one or more embodiments, the PL tool **441** may have an outer diameter of 1 11/16 inches and be powered by low-voltage PL cable **445**, which transmits power from the surface. In FIG. **4C**, the PL tool **441** includes a casing collar locator (CCL) **444** that may be used for depth control, allowing proper positioning of the PL tool **441** with respect to the metal liners **422**, **423** and insulating spacers **424**, **425**, and **426**. The depth control may be used to place the PL tool **441** in the correct position with respect to the well liner segments to be used as on-demand electrodes.

(46) FIG. **4D** shows the conveying of the PL tool into a well and converting the segmentally insulated well liners into on-demand electrodes. PL tools may be adapted to traverse liners and selectively address (ground, excite, monitor) specific segments on demand from the inside of the well liners. A standard 1 11/16 inch housing diameter PL tool would fit within a metal liner with a diameter of, for example, 4½ inches. Custom bow-spring or 4-arm bow-spring centralizers **442**, **443** may apply the electrical contact to the inner diameter (ID) of liner segments **461**, **462** as seen in FIG. **4D**. Such tools may be compatible with cartridges and logging heads with casing-collar locators (CCL) **444** for depth control; and standard cased-hole telemetry may be appropriate for this low-data-rate measurement. The PL tool **441** may be operated with excitations of a volt (or maybe up to 10 V) The PL tool **441** may operate in the frequency range between 1 Hertz and 1000 Hertz, with typical frequencies around 10 Hertz, and total currents injected into the reservoir may be on the order of tenths of an ampere (A) to a few amperes. Thus, it may be possible to operate within fairly standard cased-hole power budgets of a few tens of volt-amperes (V-A). A small-diameter coaxial cable **445** may be used to power these tools.

(47) Nonmetallic couplings or breaks between drillpipe or well casing joints have never caught on in the Industry due to concerns about reliability. Drillpipe has to sustain pressure differences and extreme bending and torques and tensions and compressions, and all that over millions of rotation cycles! Oil well casing has to sustain very large pressure differences and is often inserted from the surface, thereby experiencing very high tensions and bending to keep a long string together. However, slotted well liners or sand-screens experience much less force and bending, and that over often just one installation cycle. Slotted well liners and sand-screens do not have to sustain any pressure differences and remain static in their rather generously oversized open-hole wellbore, once installed. For these reasons, nonmetallic, insulating couplings using standard well liner thread designs may be qualified for use in that environment. Possible materials for the insulating spacers include tough ceramics, such as transition-toughened zirconia (TTZ) and reinforced thermoplastics, such as glass-fiber-reinforced PEEK, which has been qualified for a number of downhole applications, including on logging while drilling (LWD) drilling tools.

(48) FIG. **5A** shows schematically a model contemporary field with complex horizontal wells considered in a simulation study. The actual simulated domain (FIG. **5B**) was chosen to have a

good view to the encroaching waterflood and includes two horizontal well liners with each well liner consisting of four segments (1, 2, 3, 4 and 5, 6, 7, 8) separated by insulators. The modeled reservoir sizes were 2000 m×2000 m×50 to 250 m in thickness, l_z , and the well liner segment sizes were 50 m×0.2 m×0.2 m. The well separations, dx , were from 100 to 500 m. The distances, wy , between the waterfront and the wells were 100 to 900 m. The resistivity, R_1 , of the reservoir varied from 100 to 1 ohm-meters ($\Omega \cdot \text{m}$), and the resistivity, R_2 , of the waterfront varied from 1 to 100 $\Omega \cdot \text{m}$.

(49) In this simulation, a very low-frequency array operation at a few hertz (Hz) or tens of Hz is be approximated by a static (DC) analysis. The EM modeling may be performed using the open source multi-physical simulation software Elmer FEM with the static current solver. In other embodiments, a computer system may be used that is similar to the computer system **1002** that is described below in FIG. **10** and the accompanying description. The finite element meshes were prepared by Gmsh, an open-source mesh generator. Electrode 1 was kept at $V_1=1$ V, and electrodes 2-8 were kept at 0 V (compare FIG. 5B for representative current lines). The representative potential and current density fields calculated from finite element analysis are shown in FIGS. 6A and 6B, respectively.

(50) To simulate waterfront movements, the current flowed into electrode 5 (I_5) may be calculated for different waterfront-to-electrode distances (wy). We first discuss the effects of reservoir and waterfront resistivity differences. FIG. 7A shows the I_5 - wy curves with fixed waterfront resistivity $R_2=1 \Omega \cdot \text{m}$ with reservoir resistivity R_1 ranging from 1 to 100 $\Omega \cdot \text{m}$. As shown, the total current ranged from ~0.04 to 4 A. In FIG. 7A, we also plotted the normalized current changes $\Delta I/I_0$, where $\Delta I=I-I_0$ and $I_0=I$ at $wy=900$ m. It was observed that $\Delta I/I_0 > 1\%$ for $wy < 600$ m if $R_1/R_2 > 10$. FIG. 7B shows the I_5 - wy curves with fixed reservoir resistivity $R_1=100 \Omega \cdot \text{m}$ with waterfront resistivity R_2 ranging from 1 to 100 $\Omega \cdot \text{m}$. As shown, total current I_5 was all around 0.04-0.05 A. Nevertheless, one may still detect waterfront movement with $\Delta I/I_{\text{sub}.0} > 1\%$ for $wy < 600$ m if $R_1/R_2 > 5$.

(51) The effects of different geometric factors were also analyzed. FIG. 8A shows the I_5 - wy and $\Delta I/I_0$ - wy curves with electrode distances, dx , ranging from 100 to 500 m. As shown, the magnitude of I_5 increases with decreasing electrode distance, while the sensitivity for detecting waterfront movement ($\Delta I/I_0$) decreases rapidly with decreasing electrode distance. FIG. 8B shows the I_5 - wy and $\Delta I/I_0$ - wy curves with reservoir thickness, l_z , ranging from 50 to 250 m. As shown, the magnitude of I_5 increases with increasing reservoir thickness, while the sensitivity for detecting waterfront movement ($\Delta I/I_0$) decreases slightly with increasing reservoir thickness.

(52) Finally, the effect of neighboring electrodes that may divert current flows is analyzed. FIG. 9A shows the representative geometry where neighboring well liners with segments 9-16 were also fixed at 0 V. FIG. 9B shows the I_5 - wy and $\Delta I/I_0$ - wy curves with distances to the neighboring electrodes, ny , ranging from 100 to 900 m. In the same figure, the curves with no neighboring electrodes are presented. As can be seen, the neighboring electrodes reduced the magnitude of total current flowing into electrode 5 (I_5); nevertheless, the sensitivity for detecting waterfront movement ($\Delta I/I_0$) seemed not badly affected.

(53) If different wells are interrogated in a cross-well mode (or two-sided mode) as shown in FIG. 5A, the two logging units may need to be kept well phase-synchronized; but maintaining synchronization should not be difficult with access to a modern global navigation satellite system (GNSS), for example, the Global Positioning System (GPS). Using short tool-strings and cased-hole wireline tractors to convey the PL tools, the deployment cost may be much lower than with coiled tube conveyance. Moreover, pressure risers and lubricators may be used to enable deployment of the PL tools without interrupting the wells' production, which would greatly relieve time pressure and eliminate lost revenue while performing these surveys. Furthermore, with measured currents of tens of milliamperes (mA) monitored for changes of several percentage points, surveys may be accomplished very quickly, with the time to move the contact electrodes

dominating over actual measurement-averaging times. Therefore, a periodic monitoring survey should not take much more time than a simple PL run under similar well conditions.

(54) In an EM survey, at least one source and one receiver are required to complete the circuit. In one-sided mode, both source and receiver can be put on a single well using one tool-string (e.g., convert well liner segments **411** as source and **414** as receiver). In two-sided mode, source and receiver are put on different wells (e.g., convert well liner segments **411** to source electrode and **410** as receiver electrode). A two-sided mode potentially may give longer range measurements than one-sided mode because the measurement range is a function of the separation between the source electrode and the receiver electrode.

(55) According to one or more embodiments, after the initial measurement, one would have a baseline current strength that may be used when monitoring the wells for changes in the waterfront.

(56) According to one or more embodiments, the EM survey may be performed repeatedly during production. If the low resistivity water is to replace the high resistivity oil when the waterfront moves closer to the wells, one may measure higher current strengths compared to the baseline. By observing the current strength changes with the help of forward modeling, one may predict the location of the waterfront **403**, that is, the boundary between the water **401** and the hydrocarbon fluid **402**, e.g. oil.

(57) In one or more embodiments, the EM survey may be optimized during production after more and more data are collected.

(58) Referring to FIG. **4A** as a simple example, originally well liner in **408** may be used as a source electrode and well liners **409** may be used as receiver electrode. After production for a few years, when the waterfront moves too close to well liners **408** and **409**, one may switch to use well liners **410** as a source and well liners **411** as receiver, for example. After further waterfront movement, possibly well liners **412** and **413** might be used for monitoring, etc.

(59) In a richer “imaging” example, one may combine the measurements from well liner **408** as source electrode and well liner **409** as receiver electrode, and well liner **410** as a second source electrode and well liners **411**, **414** as receivers electrodes, with the help of inverse modeling, to predict the precise shape of waterfront **403**.

(60) Embodiments may be implemented on a computer system. FIG. **10** is a block diagram of a computer system **1002** used to provide computational functionalities associated with described algorithms, methods, functions, processes, flows, and procedures as described in the instant disclosure, according to an implementation. The illustrated computer **1002** is intended to encompass any computing device such as a server, desktop computer, laptop/notebook computer, wireless data port, smart phone, personal data assistant (PDA), tablet computing device, one or more processors within these devices, or any other suitable processing device, including both physical or virtual instances (or both) of the computing device. Additionally, the computer **1002** may include a computer that includes an input device, such as a keypad, keyboard, touch screen, or other device that can accept user information, and an output device that conveys information associated with the operation of the computer **1002**, including digital data, visual, or audio information (or a combination of information), or a GUI.

(61) The computer **1002** can serve in a role as a client, network component, a server, a database or other persistency, or any other component (or a combination of roles) of a computer system for performing the subject matter described in the instant disclosure. The illustrated computer **1002** is communicably coupled with a network **1030**. In some implementations, one or more components of the computer **1002** may be configured to operate within environments, including cloud-computing-based, local, global, or other environment (or a combination of environments).

(62) At a high level, the computer **1002** is an electronic computing device operable to receive, transmit, process, store, or manage data and information associated with the described subject matter. According to some implementations, the computer **1002** may also include or be communicably coupled with an application server, e-mail server, web server, caching server,

streaming data server, business intelligence (BI) server, or other server (or a combination of servers).

(63) The computer **1002** can receive requests over network **1030** from a client application (for example, executing on another computer **1002**) and responding to the received requests by processing the said requests in an appropriate software application. In addition, requests may also be sent to the computer **1002** from internal users (for example, from a command console or by other appropriate access method), external or third-parties, other automated applications, as well as any other appropriate entities, individuals, systems, or computers.

(64) Each of the components of the computer **1002** can communicate using a system bus **1003**. In some implementations, any or all of the components of the computer **1002**, both hardware or software (or a combination of hardware and software), may interface with each other or the interface **1004** (or a combination of both) over the system bus **1003** using an application programming interface (API) **1012** or a service layer **1013** (or a combination of the API **1012**) and service layer **1013**. The API **1012** may include specifications for routines, data structures, and object classes. The API **1012** may be either computer-language independent or dependent and refer to a complete interface, a single function, or even a set of APIs. The service layer **1013** provides software services to the computer **1002** or other components (whether or not illustrated) that are communicably coupled to the computer **1002**. The functionality of the computer **1002** may be accessible for all service consumers using this service layer. Software services, such as those provided by the service layer **1013**, provide reusable, defined business functionalities through a defined interface. For example, the interface may be software written in JAVA, C++, or other suitable language providing data in extensible markup language (XML) format or other suitable format. While illustrated as an integrated component of the computer **1002**, alternative implementations may illustrate the API **1012** or the service layer **1013** as stand-alone components in relation to other components of the computer **1002** or other components (whether or not illustrated) that are communicably coupled to the computer **1002**. Moreover, any or all parts of the API **1012** or the service layer **1013** may be implemented as child or sub-modules of another software module, enterprise application, or hardware module without departing from the scope of this disclosure.

(65) The computer **1002** includes an interface **1004**. Although illustrated as a single interface **1004** in FIG. **10**, two or more interfaces **1004** may be used according to particular needs, desires, or particular implementations of the computer **1002**. The interface **1004** is used by the computer **1002** for communicating with other systems in a distributed environment that are connected to the network **1030**. Generally, the interface **1004** includes logic encoded in software or hardware (or a combination of software and hardware) and operable to communicate with the network **1030**. More specifically, the interface **1004** may include software supporting one or more communication protocols associated with communications such that the network **1030** or interface's hardware is operable to communicate physical signals within and outside of the illustrated computer **1002**.

(66) The computer **1002** includes at least one computer processor **1005**. Although illustrated as a single computer processor **1005** in FIG. **10**, two or more processors may be used according to particular needs, desires, or particular implementations of the computer **1002**. Generally, the computer processor **1005** executes instructions and manipulates data to perform the operations of the computer **1002** and any algorithms, methods, functions, processes, flows, and procedures as described in the instant disclosure.

(67) The computer **1002** also includes a memory **1006** that holds data for the computer **1002** or other components (or a combination of both) that can be connected to the network **1030**. For example, memory **1006** can be a database storing data consistent with this disclosure. Although illustrated as a single memory **1006** in FIG. **10**, two or more memories may be used according to particular needs, desires, or particular implementations of the computer **1002** and the described functionality. While memory **1006** is illustrated as an integral component of the computer **1002**, in

alternative implementations, memory **1006** can be external to the computer **1002**.

(68) The application **1007** is an algorithmic software engine providing functionality according to particular needs, desires, or particular implementations of the computer **1002**, particularly with respect to functionality described in this disclosure. For example, application **1007** can serve as one or more components, modules, applications, etc. Further, although illustrated as a single application **1007**, the application **1007** may be implemented as multiple applications **1007** on the computer **1002**. In addition, although illustrated as integral to the computer **1002**, in alternative implementations, the application **1007** can be external to the computer **1002**.

(69) There may be any number of computers **1002** associated with, or external to, a computer system containing computer **1002**, each computer **1002** communicating over network **1030**. Further, the term “client,” “user,” and other appropriate terminology may be used interchangeably as appropriate without departing from the scope of this disclosure. Moreover, this disclosure contemplates that many users may use one computer **1002**, or that one user may use multiple computers **1002**.

(70) While the invention has been described with respect to a limited number of embodiments, those skilled in the art, having the benefit of this disclosure, will appreciate that other embodiments can be devised that do not depart from the scope of the invention as described herein. Accordingly, the scope of the invention should be limited only by the accompanying claims.

Claims

1. A system for monitoring waterfront movement in a subsurface formation, the system comprising: a plurality of well liners disposed in at least one well, wherein each well liner comprises an electrically conductive material having a shape of a hollow cylinder; at least one electrically insulating spacer disposed between two of the plurality of well liners to form at least one on-demand electromagnetic source electrode; at least one electrically insulating spacer disposed between two of the plurality of well liners to form at least one on-demand electromagnetic receiver electrode; a well logging tool comprising: a cylindrical housing having an outer diameter less than an inner diameter of the hollow cylinder; a plurality of insulated centralizers disposed around the cylindrical housing; a plurality of electrical connections that selectively connect to at least one of the plurality of well liners; a power connection that receives power from a surface location; and a communication connection that communicates with the surface location; and a conveyor that disposes the well logging tool within the plurality of well liners.
 2. The system according to claim 1, further comprising: performing a plurality of electromagnetic waterfront surveys separated by a plurality of time delays; performing inverse modeling of the waterfront surveys; and producing, based the inverse modeling, a water saturation change image.
 3. The system according to claim 1, wherein the at least one on-demand electromagnetic source electrode, and the at least one on-demand electromagnetic receiver electrode are located in different wellbores.
 4. The system according to claim 1, wherein one of the plurality of well liners has a plurality of openings formed therein.
 5. The system according to claim 4, wherein the openings are elongated slots.
 6. The system according to claim 1, wherein the plurality of well liners are disposed in a plurality of wells and a well logging tool disposed in each of the plurality of wells.
 7. The system according to claim 1, wherein the well logging tool further comprises a casing collar locator that indicates a position of the well logging tool relative to the well liners and the insulating spacer.
 8. The system according to claim 1, wherein each of the plurality of electrical connections may be switched to one of a ground, an excited, or a monitoring, state.
-

