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(54) Title: AUTOMATED TRAJECTORY AND ANTI-COLLISION FOR WELL PLANNING

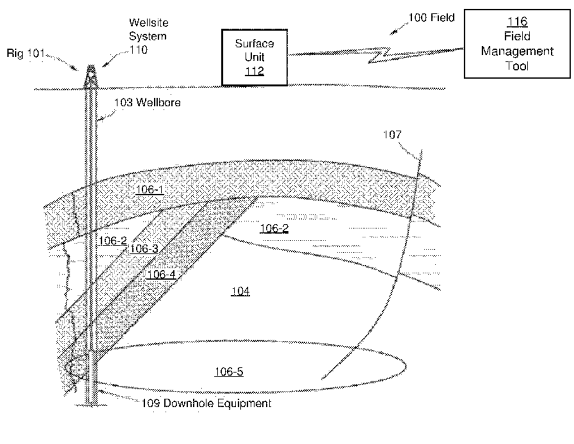

FIG. 1

(57) Abstract: A system, a method, and a non-transitory computer readable medium (CRM) for well planning are provided. Various parameters and weights associated with a reservoir are sent to an optimizer (604). Example parameters include the starting location and ending location of one or more well paths plus anti-collision consideration. After one or more iterations, the optimizer generates one or more well paths (606). One or more types of engineering analysis may be performed on the well paths (608). One or more of the well paths may be displayed to a user and/or drilled in the reservoir (610).

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AUTOMATED TRAJECTORY AND ANTI-COLLISION FOR WELL PLANNING

BACKGROUND

[0001] Operations, such as geophysical surveying, drilling, logging, well completion, and production, are performed to locate and gather valuable downhole fluids from subterranean formations. In order to extract fluids, the trajectories of the wells are carefully determined. Planning the trajectory may include identifying constraints to the trajectory caused by subsurface formations and existence of nearby wells.

BRIEF DESCRIPTION OF DRAWINGS

[0002] FIG. 1 shows a schematic view of a field in accordance with one or more embodiments.

[0003] FIG. 2 shows a schematic view of a wellsite in accordance with one or more embodiments of the present disclosure .

[0004] FIG. 3 shows a schematic diagram depicting a drilling operation of a directional well in multiple sections in accordance with one or more embodiments of the present disclosure .

[0005] FIG. 4 shows an oilfield for performing production operations in accordance with one or more embodiments of the present disclosure .

[0006] FIG. 5 shows a field management tool in accordance with one or more embodiments of the present disclosure .

[0007] FIG. 6 shows a flowchart in accordance with one or more embodiments of the present disclosure .

[0008] FIG. 7 shows a computing system in accordance with one or more embodiments of the present disclosure .

DETAILED DESCRIPTION

[0009] Specific embodiments of the present disclosure will now be described in detail with reference to the accompanying figures. Like elements in the various figures are denoted by like reference numerals for consistency.

[0010] In the following detailed description of embodiments of the present disclosure , numerous specific details are set forth in order to provide a more thorough understanding of the present disclosure . However, it will be apparent to one of ordinary skill in the art that the present disclosure may be practiced without these specific details. In other instances, well-known features have not been described in detail to avoid unnecessarily complicating the description.

[0011] 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 by the use of 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.

[0012] In general, embodiments of the present disclosure relate to a system, a method, and a non-transitory computer readable medium (CRM) for well planning. Various parameters and weights associated with a reservoir are sent to an optimizer. Example parameters include the starting location and ending location of one or more well paths plus anti-collision consideration. After one or more iterations, the optimizer generates one or more well paths. One or more types of engineering analysis may be performed on the well paths. One or more of the well paths may be displayed to a user and/or drilled in the reservoir.

[0013] FIG. 1 depicts a schematic view, partially in cross section, of a field (100) in which one or more embodiments may be implemented. In one or more embodiments, the field may be an oilfield. In other embodiments, the field may be a different type of field. In one or more embodiments, one or more of the modules and elements shown in FIG. 1 may be omitted, repeated, and/or substituted. Accordingly, embodiments should not be considered limited to the specific arrangements of modules shown in FIG. 1.

[0014] A subterranean formation (104) is in an underground geological region. An underground geological region is a geographic area that exists below land or ocean. In one or more embodiments, the underground geological region includes the subsurface formation in which a borehole is or may be drilled and any subsurface region that may affect the drilling of the borehole, such as because of stresses and strains existing in the subsurface region. In other words, the underground geological region may not only include the area immediately surrounding a borehole or where a borehole may be drilled, but also any area that affects or may affect the borehole or where the borehole may be drilled.

[0015] As shown in FIG. 1, the subterranean formation (104) may include several geological structures (106-1 through 106-4) of which FIG. 1 provides an example. As shown, the formation may include a sandstone layer (106-1), a limestone layer (106-2), a shale layer (106-3), and a sand layer (106-4). A fault line (107) may extend through the formation. In one or more embodiments, various survey tools and/or data acquisition tools are adapted to measure the formation and detect the characteristics of the geological structures of the formation. Further, the wellsite system (110) is associated with a rig (101), a wellbore (103), and other field equipment and is configured to perform wellbore operations, such as logging, drilling, fracturing, production, or other applicable operations. The wellbore (103) may also be referred to as a borehole.

[0016] In one or more embodiments, the surface unit (112) is operatively coupled to a field management tool (116) and/or the wellsite system (110). In particular, the surface unit (112) is configured to communicate with the field management tool (116) and/or the wellsite system (110) to send commands to the field management tool (116) and/or the wellsite system (110) and to receive data therefrom. For example, the wellsite system (110) may be adapted for measuring downhole properties using logging-while-drilling ("LWD") tools to obtain well logs and for obtaining core samples. In one or more embodiments, the surface unit (112) may be located at the wellsite system (110) and/or remote locations. The surface unit (112) may be provided with computer facilities for receiving, storing, processing, and/or analyzing data from the field management tool (116), the wellsite system (110), or other part of the field (100). The surface unit (112) may also be provided with or functionally for actuating mechanisms at the field (100). The surface unit (112) may then send command signals to the field (100) in response to data received, for example, to control and/or optimize various field operations described above.

[0017] During the various oilfield operations at the field, data is collected for analysis and/or monitoring of the oilfield operations. Such data may include, for example, subterranean formation, equipment, historical and/or other data. Static data relates to, for example, formation structure and geological stratigraphy that define the geological structures of the subterranean formation. Static data may also include data about the wellbore, such as inside diameters, outside diameters, and depths. Dynamic data relates to, for example, fluids flowing through the geologic structures of the subterranean formation over time. The dynamic data may include, for example, pressures, fluid compositions (e.g. gas oil ratio, water cut, and/or other fluid compositional information), and states of various equipment, and other information.

[0018] The static and dynamic data collected from the wellbore and the oilfield may be used to create and update a three dimensional model of the subsurface formations. Additionally, static and dynamic data from other wellbores or oilfields may be used to create and update the three dimensional model. Hardware sensors, core sampling, and well logging techniques may be used to collect the data. Other static measurements may be gathered using downhole measurements, such as core sampling and well logging techniques. Well logging involves deployment of a downhole tool into the wellbore to collect various downhole measurements, such as density, resistivity, etc., at various depths. Such well logging may be performed using, for example, a drilling tool and/or a wireline tool, or sensors located on downhole production equipment. Once the well is formed and completed, fluid flows to the surface using production tubing and other completion equipment. As fluid passes to the surface, various dynamic measurements, such as fluid flow rates, pressure, and composition may be monitored. These parameters may be used to determine various characteristics of the subterranean formation.

[0019] In one or more embodiments, the data is received by the surface unit (112), which is communicatively coupled to the field management tool (116). Generally, the field management tool (116) is configured to analyze, model, control, optimize, or perform other management tasks of the aforementioned field operations based on the data provided from the surface unit (112). Although the surface unit (112) is shown as separate from the field management tool (116) in FIG. 1, in other examples, the surface unit (112) and the field management tool (116) may also be combined.

[0020] FIG. 2 is a schematic view of a wellsite (200) depicting a drilling operation. In one or more embodiments, drilling tools are deployed from the oil and gas rigs. The drilling tools advanced into the earth along a path to locate reservoirs containing the valuable downhole assets. In one or more embodiments, the optimal path for the drilling is identified in a well plan that uses three dimensional modeling.

[0021] Fluid, such as drilling mud or other drilling fluids, is pumped down the wellbore (or borehole) through the drilling tool and out the drilling bit. In one or more embodiments, the amount of fluid pumped into the well is defined by the drilling density. Specifically, the drilling density is the upper and lower bounds of equivalent hydraulic pressure acting over borehole walls to create failure of the borehole. Because the amount and type of fluid directly affects the hydraulic pressure on the borehole walls, calculating the drilling density and using the drilling density defines the amount and type of fluid to pump down the wellbore. Continuing with the discussion of FIG. 1, the drilling fluid flows through the annulus between the drilling tool and the wellbore and out the surface, carrying away earth loosened during drilling. The drilling fluids return the earth to the surface, and seal the wall of the wellbore to prevent fluid in the surrounding earth from entering the wellbore and causing a ‘blow out’.

[0022] During the drilling operation, the drilling tool may perform downhole measurements to investigate downhole conditions. The drilling tool may be used to take core samples of subsurface formations. In some cases, the drilling tool is removed and a wireline tool is deployed into the wellbore to perform additional downhole testing, such as logging or sampling. Steel casing may be run into the well to a desired depth and cemented into place along the wellbore wall. Drilling may be continued until the desired total depth is reached.

[0023] After the drilling operation is complete, the well may then be prepared for production. Wellbore completions equipment is deployed into the wellbore to complete the well in preparation for the production of fluid through the wellbore. Fluid is then allowed to flow from downhole reservoirs, into the wellbore and to the surface. Production facilities are positioned at surface locations to collect the hydrocarbons from the wellsite(s). Fluid drawn from the subterranean reservoir(s) passes to the production facilities via transport mechanisms, such as tubing. Various equipments may be positioned about the oilfield to monitor oilfield parameters, to manipulate the oilfield operations and/or to separate and direct fluids from the wells. Surface equipment and completion equipment may also be used to inject fluids into reservoir either for storage or at strategic points to enhance production of the reservoir.

[0024] Continuing with FIG. 2, the wellsite system (200) includes a drilling system (211) and a surface unit (234). In the illustrated embodiment, a borehole (213) is formed by rotary drilling in a manner that is well known. Although rotary drilling is shown, embodiments also include drilling applications other than conventional rotary drilling (*e.g.*, mud-motor based directional drilling), and is not limited to land-based rigs. For example, embodiments may be used to perform three dimensional modeling and drilling of a deep water operation.

[0025] The drilling system (211) includes a drill string (215) suspended within the borehole (213) with a drill bit (210) at its lower end. The drilling system (211) also includes the land-based platform and derrick assembly (212) positioned over the borehole (213) penetrating a subsurface formation (F). The assembly (212) includes a rotary table (214), kelly (216), hook (218) and rotary swivel (219). The drill string (215) is rotated by the rotary table (214), energized by means not shown, which engages the kelly (216) at the upper end of the drill string. The drill string (215) is suspended from hook (218), attached to a traveling block (also not shown), through the kelly (216) and a rotary swivel (219) which permits rotation of the drill string relative to the hook.

[0026] The drilling system (211) further includes drilling fluid or mud (220) stored in a pit (222) formed at the well site. A pump (224) delivers the drilling fluid (220) to the interior of the drill string (215) via a port in the swivel (219), inducing the drilling fluid to flow downwardly through the drill string (215) as indicated by the directional arrow (225). The drilling fluid exits the drill string (215) via ports in the drill bit (210), and then circulates upwardly through the region between the outside of the drill string and the wall of the borehole, called the annulus (226). In this manner, the drilling fluid lubricates the drill bit (210) and carries formation cuttings up to the surface as it is returned to the pit (222) for recirculation.

[0027] The drill string (215) further includes a bottom hole assembly (BHA), generally referred to as (230), near the drill bit (210) (in other words, within several drill collar lengths from the drill bit). The bottom hole assembly (230) includes capabilities for measuring, processing, and storing information, as well as communicating with the surface unit. The BHA (230) further includes drill collars (228) for performing various other measurement functions.

[0028] Sensors (S) are located about the wellsite to collect data, may be in real time, concerning the operation of the wellsite, as well as conditions at the wellsite. The sensors may also have features or capabilities, of monitors, such as cameras (not shown), to provide pictures of the operation. Surface sensors or gauges S may be deployed about the surface systems to provide information about the surface unit, such as standpipe pressure, hook load, depth, surface torque, rotary rpm, among others. Downhole sensors or gauges (S) are disposed about the drilling tool and/or wellbore to provide information about downhole conditions, such as wellbore pressure, weight on bit, torque on bit, direction, inclination, collar rpm, tool temperature, annular temperature, and toolface, among others. The information collected by the sensors and cameras is conveyed to the various parts of the drilling system and/or the surface control unit.

[0029] The drilling system (210) is operatively connected to the surface unit (234) for communication therewith. The BHA (230) is provided with a communication subassembly (252) that communicates with the surface unit (234). The communication subassembly (252) is adapted to send signals to and receive signals from the surface using mud pulse telemetry. The communication subassembly may include, for example, a transmitter that generates a signal, such as an acoustic or electromagnetic signal, which is representative of the measured drilling parameters. Communication between the downhole and surface systems is depicted as being mud pulse telemetry. However, a variety of telemetry systems may be employed, such as wired drill pipe, electromagnetic or other known telemetry systems.

[0030] FIG. 3 shows a schematic diagram depicting drilling operation of a directional well in multiple sections. The drilling operation depicted in FIG. 2 includes a wellsite drilling system (300) and a field management tool (320) for accessing fluid in the target reservoir through a bore hole (350) of a directional well (317). The wellsite drilling system (300) includes various components (*e.g.*, drill string (312), annulus (313), bottom hole assembly (BHA) (314), Kelly (315), mud pit (316), etc.) as generally described with respect to the wellsite drilling systems (100) (*e.g.*, drill string (115), annulus (126), bottom hole assembly (BHA) (130), Kelly (116), mud pit (122), etc.) of FIG. 1 above. As shown in FIG. 2, the target reservoir may be located away from (as opposed to directly under) the surface location of the well (317). Accordingly, special tools or techniques may be used to ensure that the path along the bore hole (350) reaches the particular location of the target reservoir (300).

[0031] For example, the BHA (314) may include sensors (308), rotary steerable system (309), and the bit (310) to direct the drilling toward the target guided by a pre-determined survey program for measuring location details in the well. Furthermore, the subterranean formation through which the directional well (317) is drilled may include multiple layers (not shown) with varying compositions, geophysical characteristics, and geological conditions. Both the drilling planning during the well design stage and the actual drilling according to the drilling plan in the drilling stage may be performed in multiple sections (*e.g.,* sections (301), (302), (303), (304)) corresponding to the multiple layers in the subterranean formation. For example, certain sections (*e.g.,* sections (301) and (302)) may use cement (307) reinforced casing (306) due to the particular formation compositions, geophysical characteristics, and geological conditions.

[0032] Further as shown in FIG. 2, surface unit (311) (as generally described with respect to the surface unit (134) of FIG. 1) may be operatively linked to the wellsite drilling system (300) and the field management tool (320) via communication links (318). The surface unit (311) may be configured with functionalities to control and monitor the drilling activities by sections in real-time via the communication links (318). The field management tool (320) may be configured with functionalities to store oilfield data (*e.g.,* historical data, actual data, surface data, subsurface data, equipment data, geological data, geophysical data, target data, anti-target data, etc.) and determine relevant factors for configuring a drilling model and generating a drilling plan. The oilfield data, the drilling model, and the drilling plan may be transmitted via the communication link (318) according to a drilling operation workflow. The communication link (318) may comprise the communication subassembly (352) as described with respect to FIG. 1 above.

[0033] FIG. 4 illustrates the oilfield (400) for performing production operations. As shown, the oilfield may have multiple wellsites (402) operatively connected to a central processing facility (454). The oilfield configuration of FIG. 4 is not intended to limit the scope. Part or all of the oilfield may be on land and/or sea. Also, while a single oilfield with a single processing facility and a plurality of wellsites is depicted, any combination of one or more oilfields, one or more processing facilities, and one or more wellsites may be present.

[0034] As discussed above, each wellsite (402) has equipment that forms a wellbore (436) into the earth. The wellbores extend through subterranean formations (406) including reservoirs (404). These reservoirs (404) include fluids, such as hydrocarbons. The wellsites draw fluid from the reservoirs and pass them to the processing facilities via oilfield networks (444). The oilfield networks (444) have tubing and control mechanisms for controlling the flow of fluid and/or gas from the wellsite to the processing facility (454).

[0035] Wellbore production equipment (464) extends from a wellhead (466) of wellsite (402) and to the reservoir (404) to draw fluid to the surface. The wellsite (402) is operatively connected to the oilfield network (444) via a transport line (464). Fluid flows from the reservoir (404), through the wellbore (436), and onto the oilfield network (444). The fluid then flows from the oilfield network (444) to one or more processing facilities (454).

[0036] The analyzed data may then be used to make decisions. A transceiver (not shown) may be provided to allow communications between the surface unit and the oilfield. A controller may be used to actuate mechanisms at the oilfield via the transceiver and based on these decisions. In this manner, the oilfield may be selectively adjusted based on the data collected. These adjustments may be made automatically based on computer protocol and/or manually by an operator. In some cases, well plans are adjusted to select optimum operating conditions or to avoid problems.

[0037] To facilitate the processing and analysis of data, simulators may be used to process the data. Specific simulators are often used in connection with specific oilfield operations, such as reservoir or wellbore production. Data fed into the simulator(s) may be historical data, real time data or combinations thereof. Simulation through one or more of the simulators may be repeated or adjusted based on the data received.

[0038] The oilfield operation is provided with wellsite and non-wellsite simulators. The wellsite simulators may include a reservoir simulator, a wellbore simulator, and a surface network simulator. The reservoir simulator solves for hydrocarbon flowrate through the reservoir and into the wellbores. The wellbore simulator and surface network simulator solve for hydrocarbon flowrate through the wellbore and the surface gathering network of pipelines. As shown, some of the simulators may be separate or combined, depending on the available systems.

[0039] The non-wellsite simulators may include process and economics simulators. The processing unit has a process simulator. The process simulator models the processing plant (*e.g.*, the process facility) where the hydrocarbon is separated into its constituent components (*e.g.*, methane, ethane, propane, etc.) and prepared for sales. The oilfield is provided with an economics simulator. The economics simulator models the costs of part or all of the oilfield. Various combinations of these and other oilfield simulators may be provided.

[0040] FIG. 5 shows a schematic diagram of a system in accordance with one or more embodiments. As shown in FIG. 5, the field management tool (116) is a tool that is configured to perform management operations of the field. In some embodiments, the field management tool (116) may be a software tool configured to execute on a computing system, such as the computing system shown in FIG. 7. In some embodiments, the field management tool (116) may be a hardware tool, such as a computing system, and may or may not include specialized equipment for management of the field. The field management tool (116) includes a repository (525), a portal (502), an optimizer (505), and one or more modules: anti-collision module (512), torque & drag module (514), hydraulics module (516), and geometrics module (518) in accordance with one or more embodiments. In one or more embodiments, each of these components (502, 505, 512, 514, 516, 518, 525) may be located on the same hardware device or different hardware devices separated by networks of any size having wired and/or wireless segments. Additionally or alternatively, one or more of the components (502, 505, 512, 514, 516, 518, 525) may be plugins to other applications (not shown) and/or may be accessed by plugins. Additionally or alternatively, one or more of the components (502, 505, 512, 514, 516, 518, 525) may be located in a cloud computing infrastructure. The field management tool (116) may be used anywhere at any time (*e.g.*, at the rigsite during drilling, in an office while planning the job, etc.).

[0041] In one or more embodiments, the optimizer (505) includes functionality to generate one or more well paths. Specifically, the optimizer (505) may generate well paths based on one or more weighted parameters that are inputs to the optimizer (505). The weighted parameters may act as constraints on the optimizer (505) during the generation of the well paths. According to an embodiment, the optimizer (505) may invoke an iterative process to generate the well paths. In one or more embodiments, one or more of the iterations access one or more of the modules (512, 514, 516, 518) in order to generate the well paths. The frequency with which each module (512, 514, 516, 518) is accessed may depend on the weighted parameters. The modules (512, 514, 516, 518) may provide one or more of the parameters. In one or more embodiments, the optimizer (505) generates well paths that do not collide with each other and/or with existing wells in the reservoir. In one or more embodiments, the optimizer (505) generates well paths that have the same starting location (*e.g.*, same pad or platform) in the field. Additional details regarding the parameters and the weights are discussed below.

[0042] In one or more embodiments, the field management tool (116) has multiple modules (512, 514, 516, 518). As discussed above, these modules may be accessed by the optimizer (505) to generate one or more well paths (e.g., via an application programming interface). In another embodiment, the modules (512, 514, 516, 518) may access the optimizer (505) to generate one or more well paths (e.g., via an application programming interface). In addition, one or more of the modules may execute an engineering analysis of one or more well paths generated by the optimizer (505) to determine their feasibility and/or equipment that meets certain specifications (*e.g.,* casings, drill strings, etc.) to drill the well path(s).

[0043] In one or more embodiments of the present disclosure, the field management tool (502) includes the portal (502). The portal (502) includes functionality to receive user requests to generate one or more well paths. The portal (502) also includes functionality to present the generated well paths to a user. In particular, the portal (502) may include functionality to present a rendering of the well path(s) (e.g., in two or three dimensions). For example, the portal (502) is a graphical user interface (GUI). The portal (502) may be a web page or other interface.

[0044] In one or more embodiments, the portal (502) includes functionality to collect parameters and weights for one or more parameters selected by a user. These parameters and weights are sent to the optimizer (505) to generate the well paths.

[0045] In one or more embodiments, the repository (525) is any type of storage unit and/or device (*e.g.,* a file system, database, collection of tables, or any other storage mechanism) for storing data. Further, the data repository (525) may include multiple different storage units and/or devices. The multiple different storage units and/or devices may or may not be of the same type or located at the same physical site.

[0046] As shown in FIG. 5, the repository (525) includes one or more weight templates (527). Each weight template (527) includes a set of weights for some or all of the parameters that may be sent to the optimizer (505). By selecting one of the weight templates, a user may avoid individually specifying the weights for the parameters. The user may also use the weight templates as a coarse starting point, and then make fine adjustments to one or more of the weights.

[0047] Although not shown, the repository (525) includes functionality to store field data. Field data includes any type of data from the field. For example, field data may include, without limitation, sensor data, information about existing wells, and any other information. The field data may also be sent to the optimizer (505) in order to generate the well path(s).

[0048] The following is a non-exhaustive list of parameters that may be sent to the optimizer to generate a well path: Total drilling cost; Anti-collision with other wells; Total reservoir contact; Target location (point or volume); Vector for intersection of target; Torque & Drag results (e.g. expected weight transfer, bending moments, rig limits); Hydraulics results (keeping the downhole pressure at each depth within a certain range); Hole cleaning results; Geomechanics results (e.g. the “size” of the mud-weight window); Keeping the trajectory as short as possible; Dog-leg limits (i.e. maximum curvature); Keeping the trajectory as close to a reference/proposed/rough trajectory as possible; Preferring to keep the “straight section” of the well as long as possible; Keeping the kick-off point within a certain range; Avoiding certain risk zones; Other calculations / limits. Weights may be assigned to any of these parameters.

[0049] FIG. 6 shows a flowchart in accordance with one or more embodiments of the present disclosure. The flowchart depicts a process for well planning. One or more of the blocks in FIG. 6 may be performed by the components of the field management tool (116), discussed above in reference to FIG. 5. In one or more embodiments of the present disclosure, one or more of the blocks shown in FIG. 6 may be omitted, repeated, and/or performed in a different order than the order shown in FIG. 6. Accordingly, the scope of the present disclosure should not be considered limited to the specific arrangement of blocks shown in FIG. 6.

[0050] A trigger to generate one or more well paths is identified (Block 602). The trigger may include a user request to generate the well path(s). Additionally or alternatively, the trigger may include an update to one or more input values/objects for generating the well path(s) and/or the trigger may be the submission of the input values/objects for generating the well path(s). Additionally or alternatively, the trigger may include predetermined (*e.g.,* an automatic part of the software), and not need the user to identify the trigger.

[0051] In Block 604, parameters and weights are sent to an optimizer. Examples of parameters are listed above. The parameters and weights may be selected by a user. As also discussed above, the weights may be obtained from a weight template selected by the user.

[0052] In Block 606, the optimizer generates one or more well paths based on the parameters and weights. Generating the one or more well paths may include an iterative process. One or more iterations may include the optimizer accessing (*i.e.,* exchange data with) one or more specialized modules (*e.g.,* anti-collision module, torque & drag module, hydraulics module, and geometrics module). In one or more embodiments, the one or more well do not intersect (*i.e.,* do not collide) with each other and/or with existing wells in the reservoir. In one or more embodiments, the multiple wells may have the same starting location (*e.g.*, same pad or platform).

[0053] In one or more embodiments, the optimizer may automatically design the curved portion of the trajectory according to the specified weighted parameters, and then append a vertical section about the kick-off point, and a horizontal section below the first target.

[0054] In one or more embodiments, the optimizer may automatically design the trajectory, mud, BHA, and drilling parameters taking account of the weighted parameters.

[0055] In one or more embodiments, the optimizer may automatically choose which trajectory to tie-in to, and automatically choose the tie-in point.

[0056] In one or more embodiment, the optimizer may simultaneously design all of the trajectories (and/or other objects) for an entire pad or platform, taking into account all of the weighted parameters.

[0057] In one or more embodiments, the optimizer may "cover" the reservoir with as many wells as possible, given the above weighted parameters.

[0058] In one or more embodiments, the optimizer may adjust the trajectories (and/or other objects) for an entire pad or platform, after one or more of them has been drilled, taking into account all of the weighted parameters.

[0059] In one or more embodiments, the optimizer may allow the trajectory to contain one or more sidetracks (e.g. automatically designing a fishbone well, and deciding whether or not a fishbone is needed).

[0060] In one or more embodiments, the optimizer may automatically design the pad location and/or platform location.

[0061] In one or more embodiments, the optimizer may be able to avoid specific certain surface locations.

[0062] In one or more embodiments, the optimizer automatically design the location of multiple pads (or platforms) and/or the number of pads (or platforms) to use.

[0063] In Block 608, an engineering analysis is executed against one or more of the generated well paths.

[0064] In Block 610, one or more of the well paths are displayed to the user. A 2D or 3D rendering of the well paths may be presented to the user. One or more wells may be drilled in the reservoir based on the generated well path(s).

[0065] In one or more embodiments, one or more of the components discussed above may be implemented as or execute on a computing system. The computing system may be combination of mobile, desktop, server, embedded, or other types of hardware. For example, as shown in FIG. 7, the computing system (700) may include one or more computer processor(s) (702), associated memory (704) (*e.g.,* random access memory (RAM), cache memory, flash memory, *etc.*), one or more storage device(s) (706) (*e.g.,* a hard disk, an optical drive such as a compact disk (CD) drive or digital versatile disk (DVD) drive, a flash memory stick, *etc.*), and numerous other elements and functionalities. The computer processor(s) (702) may be an integrated circuit for processing instructions. For example, the computer processor(s) may be one or more cores, or micro-cores of a processor. The computing system (700) may also include one or more input device(s) (710), such as a touchscreen, keyboard, mouse, microphone, touchpad, electronic pen, or any other type of input device. Further, the computing system (700) may include one or more output device(s) (708), such as a screen (*e.g.,* a liquid crystal display (LCD), a plasma display, touchscreen, cathode ray tube (CRT) monitor, projector, or other display device), a printer, external storage, or any other output device. One or more of the output device(s) may be the same or different from the input device(s). The computing system (700) may be connected to a network (712) (*e.g.*, a local area network (LAN), a wide area network (WAN) such as the Internet, mobile network, or any other type of network) via a network interface connection (not shown). The input and output device(s) may be locally or remotely (*e.g.*, via the network (712)) connected to the computer processor(s) (702), memory (704), and storage device(s) (706). Many different types of computing systems exist, and the aforementioned input and output device(s) may take other forms.

[0066] Software instructions in the form of computer readable program code to perform embodiments of the present disclosure may be stored, in whole or in part, temporarily or permanently, on a non-transitory computer readable medium such as a CD, DVD, storage device, a diskette, a tape, flash memory, physical memory, or any other computer readable storage medium. Specifically, the software instructions may correspond to computer readable program code that when executed by a processor(s), is configured to perform embodiments of the present disclosure.

[0067] Further, one or more elements of the aforementioned computing system (500) may be located at a remote location and connected to the other elements over a network (512). Further, embodiments of the present disclosure may be implemented on a distributed system having a plurality of nodes, where each portion of the present disclosure may be located on a different node within the distributed system. In one embodiment of the present disclosure, the node corresponds to a distinct computing device. The node may correspond to a computer processor with associated physical memory. The node may correspond to a computer processor or micro-core of a computer processor with shared memory and/or resources.

[0068] The field management tool may further include a data repository. A data repository is any type of storage unit and/or device (*e.g.*, a file system, database, collection of tables, or any other storage mechanism) for storing data. Further, the data repository may include multiple different storage units and/or devices. The multiple different storage units and/or devices may or may not be of the same type or located at the same physical site.

[0069] While FIGs. 1-5 show various configurations of components, other configurations may be used without departing from the scope of the present disclosure. For example, various components may be combined to create a single component. As another example, the functionality performed by a single component may be performed by two or more components.

[0070] While the various steps in this flowchart are presented and described sequentially, one of ordinary skill will appreciate that some or all of the steps may be executed in different orders, may be combined or omitted, and some or all of the steps may be executed in parallel. Furthermore, the steps may be performed actively or passively. For example, some steps may be performed using polling or be interrupt driven in accordance with one or more embodiments of the present disclosure . By way of an example, determination steps may not require a processor to process an instruction unless an interrupt is received to signify that condition exists in accordance with one or more embodiments of the present disclosure . As another example, determination steps may be performed by performing a test, such as checking a data value to test whether the value is consistent with the tested condition in accordance with one or more embodiments of the present disclosure .

[0071] The following example is for explanatory purposes only and not intended to limit the scope of the present disclosure.

[0072] While the present disclosure has been described with respect to a limited number of embodiments, those skilled in the art, having benefit of this disclosure, will appreciate that other embodiments can be devised which do not depart from the scope of the present disclosure as disclosed herein. Accordingly, the scope of the present disclosure should be limited only by the attached claims.

CLAIMS

What is claimed is:

1. A method for well planning, comprising:
   identifying a trigger to generate a first well path in a reservoir;
   sending a plurality of parameters and a plurality of weights to an optimizer,
   wherein the optimizer generates the first well path based on the plurality of parameters and the plurality of weights; and
   displaying the first well path.

2. The method of claim 1, further comprising:
   executing an engineering analysis of the first well path before displaying the first well path.

3. The method of claim 1, wherein the trigger is a request from a user.

4. The method of claim 1, wherein the plurality of parameters comprises a starting location for the first well path and at least one ending locations for the first well path.

5. The method of claim 1, wherein the plurality of parameters includes a well that already exists in the reservoir before the trigger is identified.

6. The method of claim 1, wherein:
   the plurality of parameters comprises a starting location for the first well path, an ending location for the first well path, an ending location for a second well path, and an anti-collision consideration; and
   the optimizer further generates, with the first well path, a second well path based on the starting location, the ending location for the second well path, and the anti-collision consideration.

7. A non-transitory computer readable medium (CRM) storing instructions for well planning, the instructions comprising functionality for:
   identifying a trigger to generate a first well path in a reservoir;
   sending a plurality of parameters and a plurality of weights to an optimizer,
   wherein the optimizer generates the first well path based on the plurality of parameters and the plurality of weights; and
   displaying the first well path.

8. The non-transitory CRM of claim 7, the instructions further comprising functionality for:
   executing an engineering analysis of the first well path before displaying the first well path.

9. The non-transitory CRM of claim 7, wherein the trigger is a request from a user.

10. The non-transitory CRM of claim 7, wherein the plurality of parameters comprises a starting location for the first well path and at least one ending locations for the first well path.

11. The non-transitory CRM of claim 7, wherein the plurality of parameters includes a well that already exists in the reservoir before the trigger is identified.

12. The non-transitory CRM of claim 7, wherein:
   the plurality of parameters comprises a starting location for the first well path, an ending location for the first well path, an ending location for a second well path, and an anti-collision consideration; and
   the optimizer further generates, with the first well path, a second well path based on the starting location, the ending location for the second well path, and the anti-collision consideration.

13. A system for well planning, comprising:

    a portal to collect a plurality of parameters and a plurality of weights associated with a reservoir; and

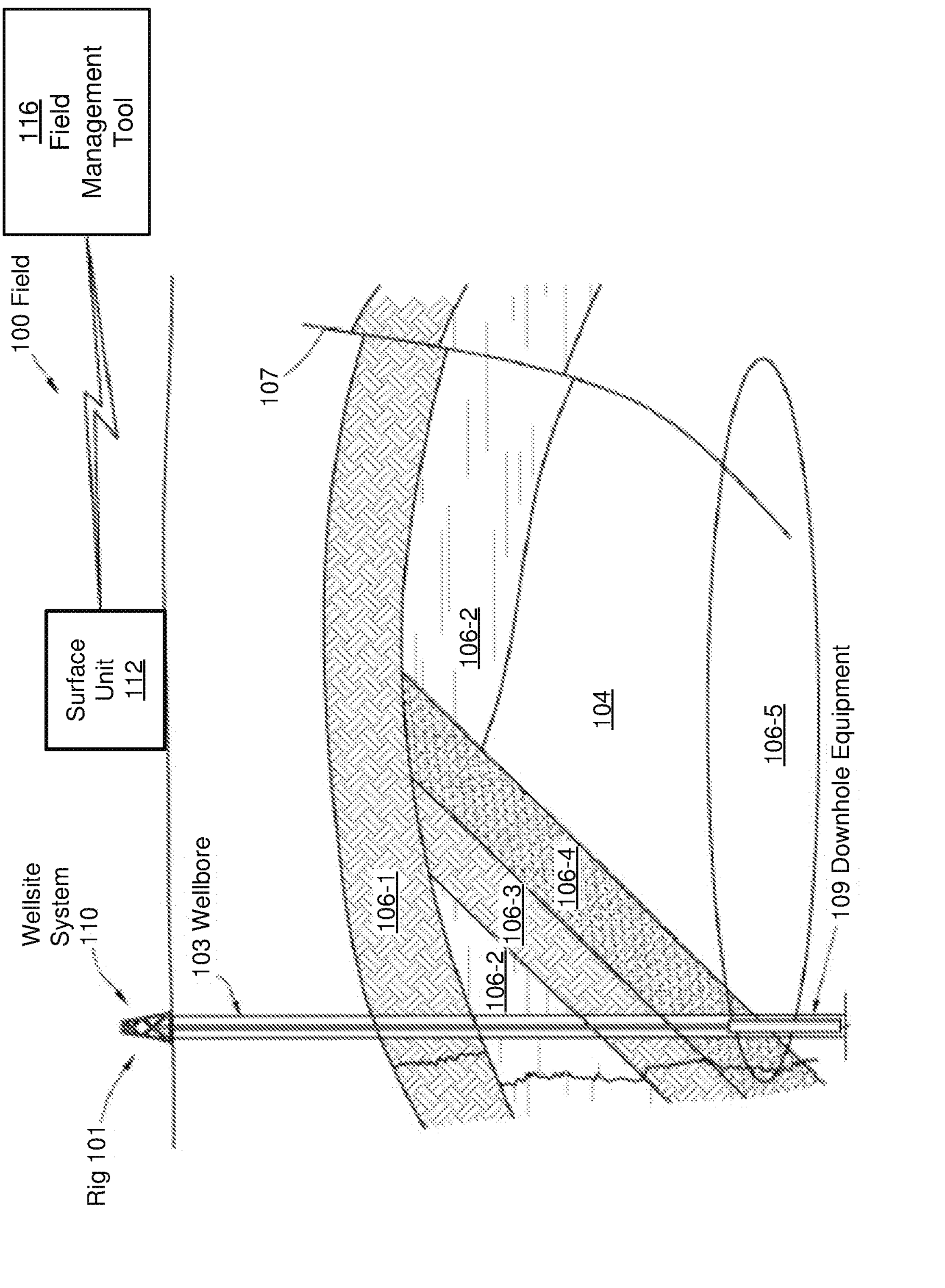
    an optimizer connected to the portal and configured to generate a first well path in the reservoir based on the plurality of weights and the plurality of weights.

14. The system of claim 13, further comprising:

    a repository connected to the portal and storing a plurality of weight comprising the plurality of weights.

15. The system of claim 13, further comprising:

    an anti-collision module accessed by the optimizer to prevent the first well path from intersecting a second well path in the reservoir.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Wellsite
System
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Rig 101
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106-1
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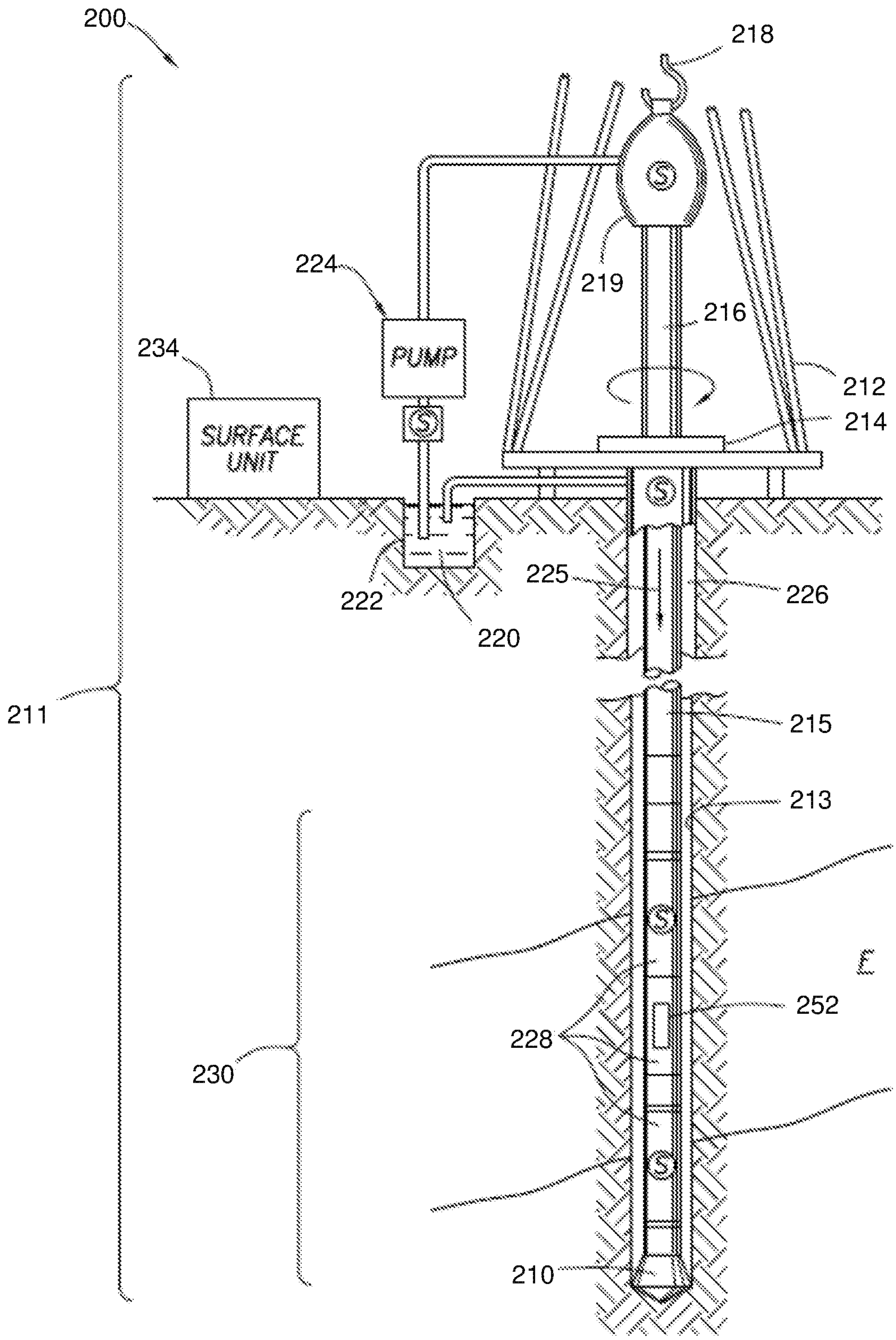
106-3
106-4
106-2
104
106-5
109 Downhole Equipment

FIG. 1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224
219
216
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PUMP
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226
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220
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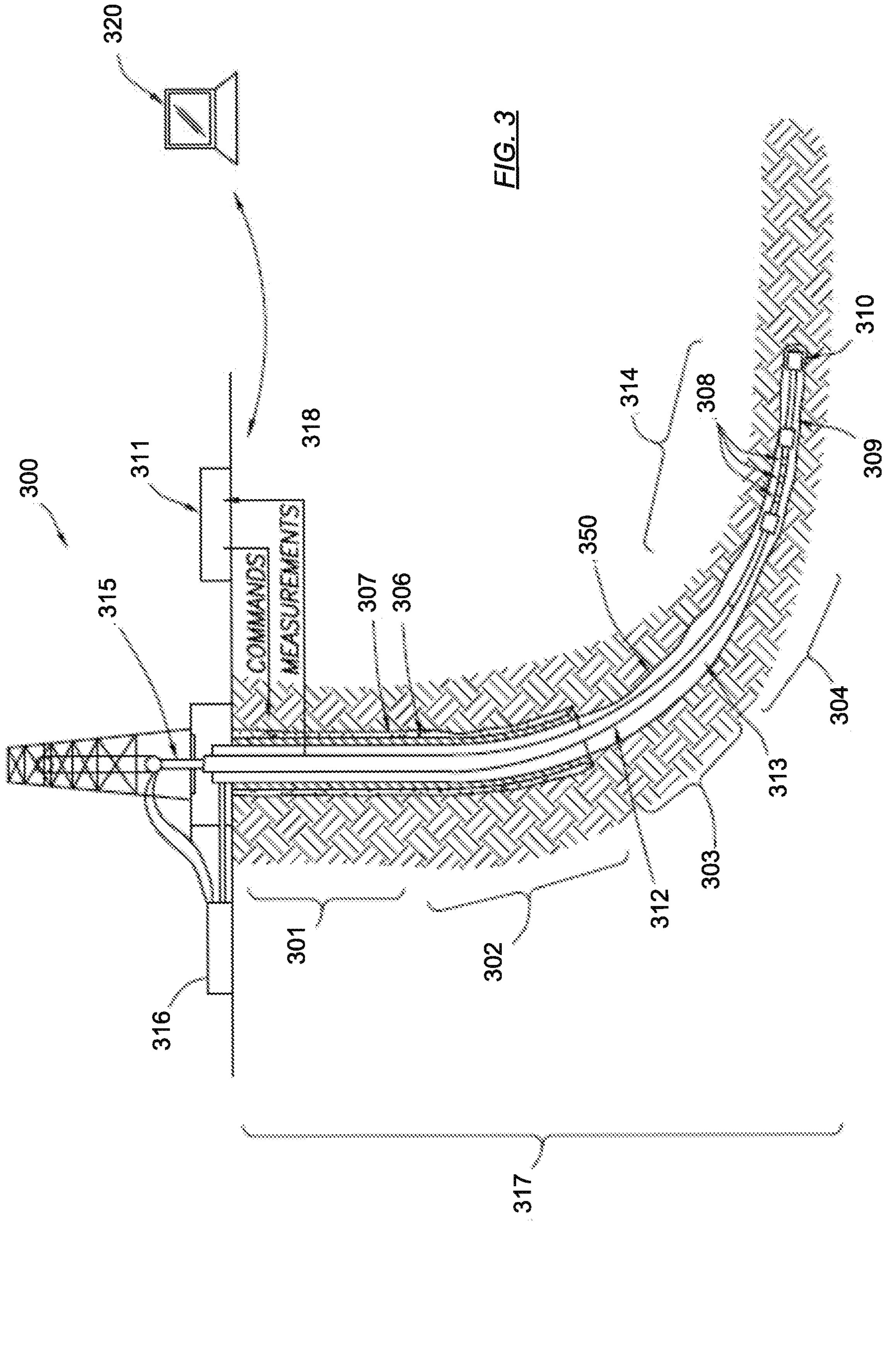
230
210

FIG. 2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COMMANDS
MEASUREMENTS
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FIG. 3

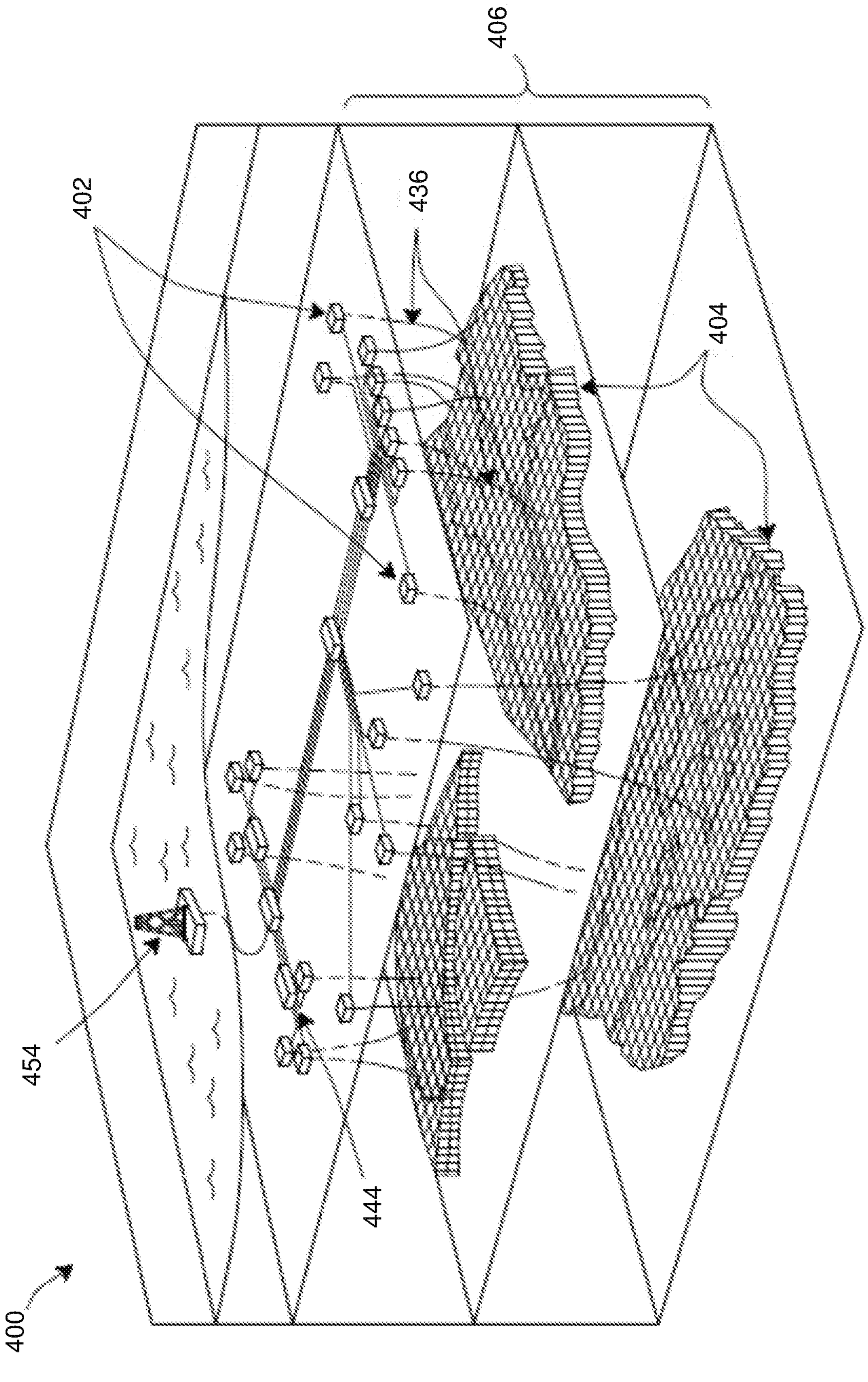
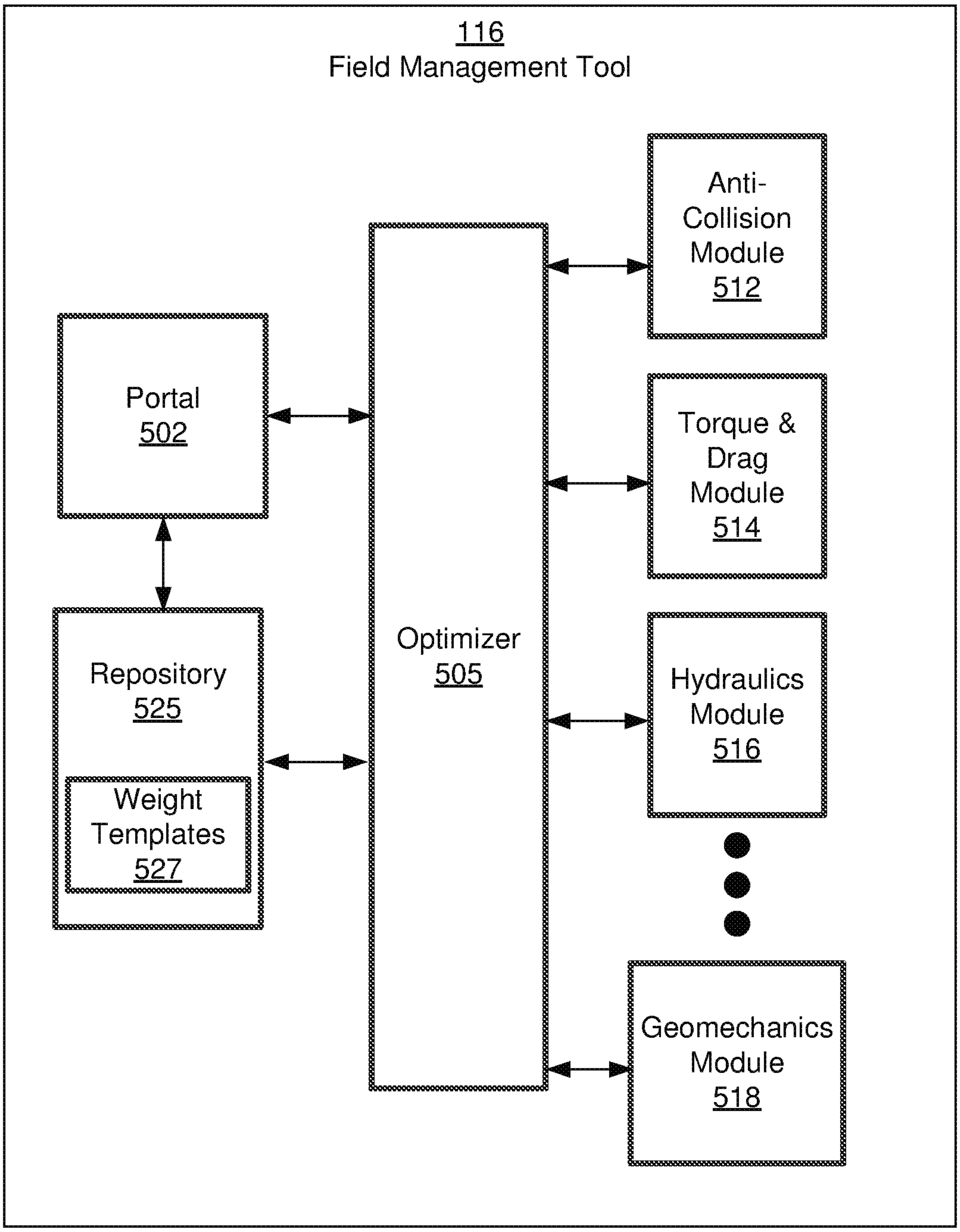


FIG. 4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Field Management Tool
Portal
502
Repository
525
Weight
Templates
527
Optimizer
505
Anti-
Collision
Module
512
Torque &
Drag
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514
Hydraulics
Module
516
Geomechanics
Module
518

FIG. 5

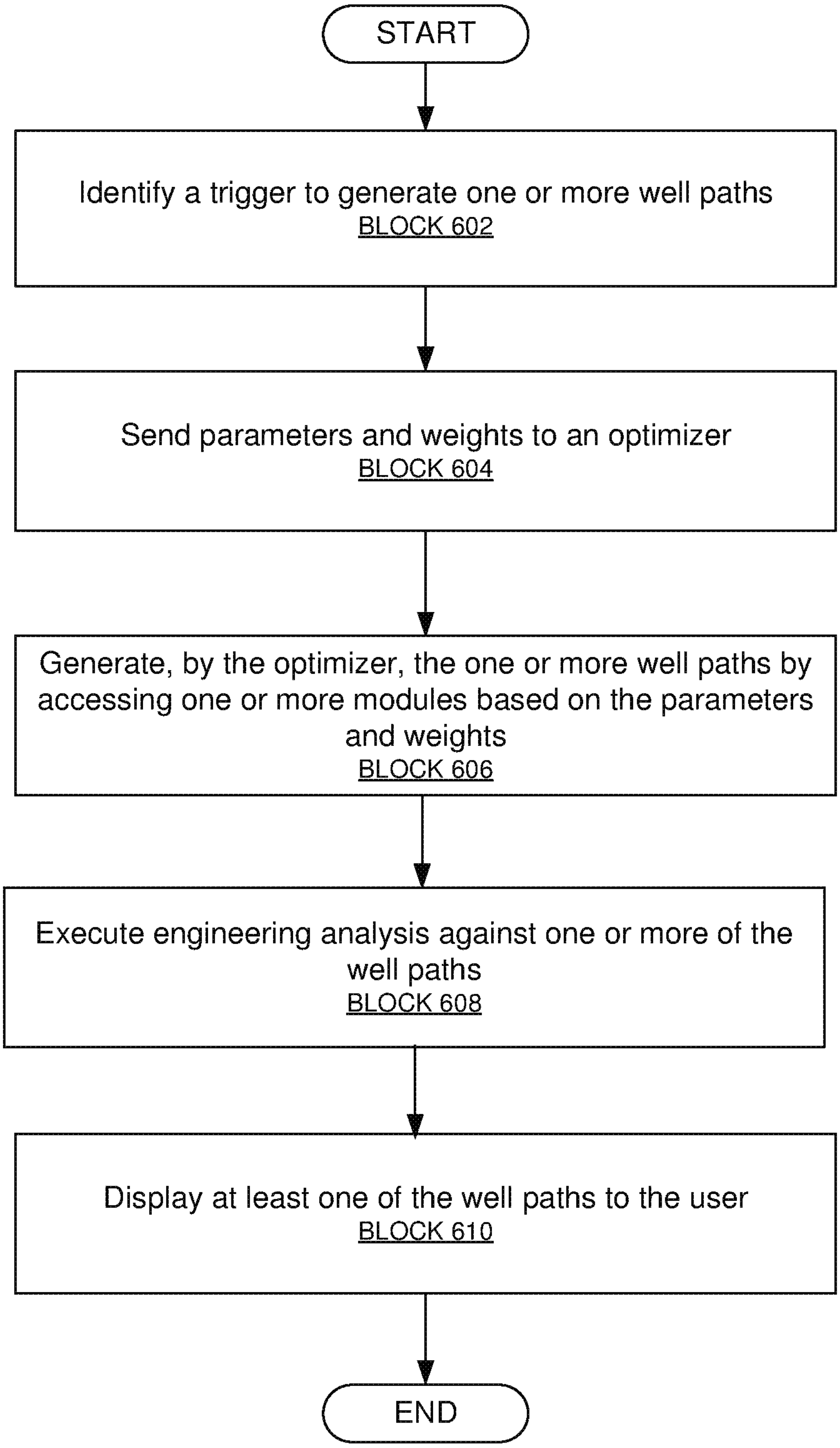
START
Identify a trigger to generate one or more well paths
BLOCK 602
Send parameters and weights to an optimizer
BLOCK 604
Generate, by the optimizer, the one or more well paths by accessing one or more modules based on the parameters and weights
BLOCK 606
Execute engineering analysis against one or more of the well paths
BLOCK 608
Display at least one of the well paths to the user
BLOCK 610
END

FIG. 6

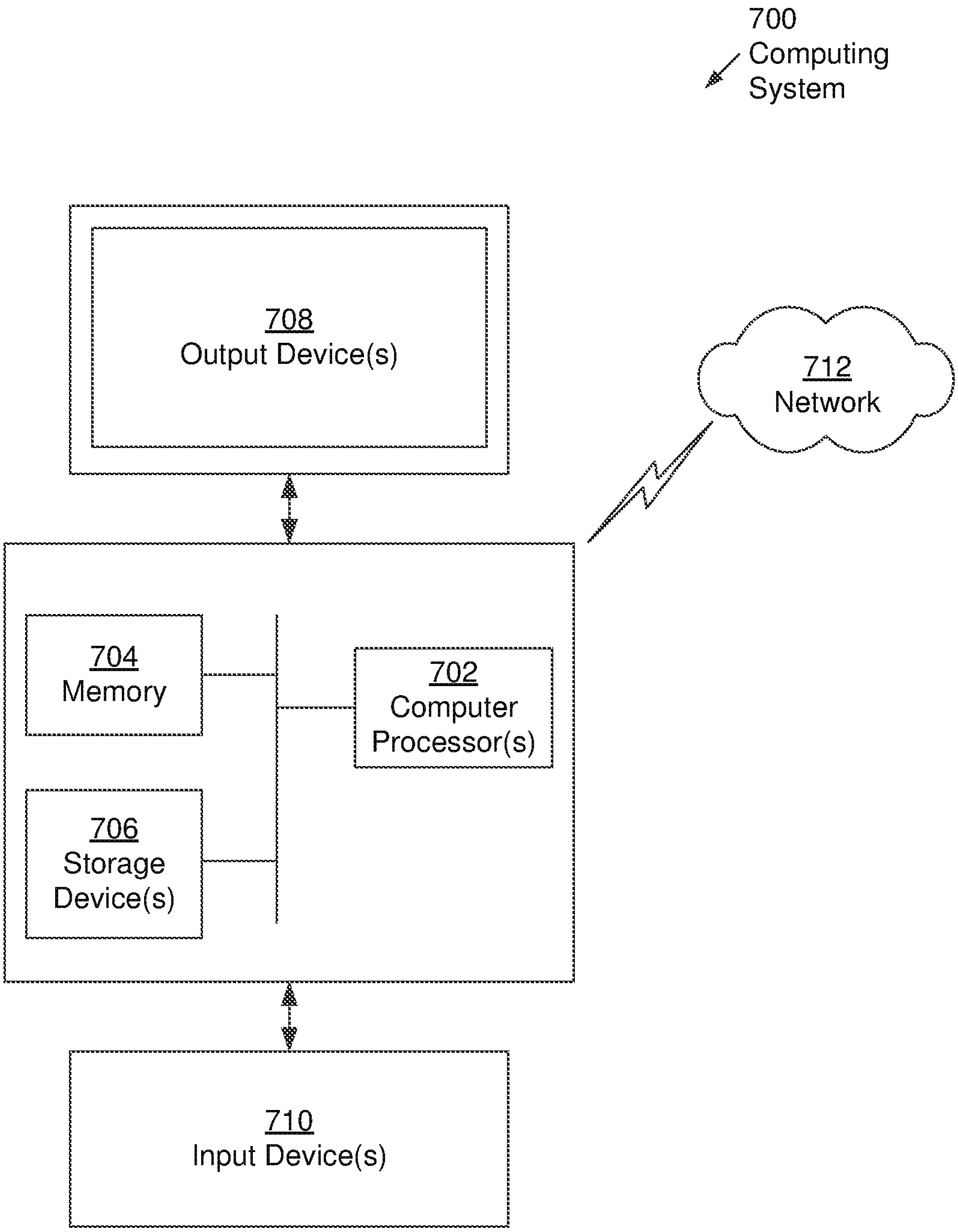
700
Computing
System
708
Output Device(s)
712
Network
704
Memory
702
Computer
Processor(s)
706
Storage
Device(s)
710
Input Device(s)

FIG. 7

INTERNATIONAL SEARCH REPORT

International application No.
PCT/CN2015/076928

A. CLASSIFICATION OF SUBJECT MATTER

E21B 47/00(2012.01)i

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

E21B

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

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

CNPAT, CNKI, EPODOC, WPI, EI, ISI, GOOGLE: prad research, bolchover, LIU Qing, well, plan????, path?, route?, wellpath?, track+, trajectory, parameter?, weight+

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2013140037 A1 (JR.， JOSE J. SEQUEIRA ET AL.) 06 June 2013 (2013-06-06) description paragraphs [0051]-[0070]， [0090]-[0102]， [0109]-[0112]， figures 1-2， 6-7 and 9	1-15
A	US 2014005996 A1 (SCHLUMBERGER TECHNOLOGY CORPORATION) 02 January 2014 (2014-01-02) the whole document	1-15
A	WO 2009032416 A1 (EXXONMOBILL UPSTREAM RESEARCH COMPANY) 12 March 2009 (2009-03-12) the whole document	1-15
A	WO 2013062591 A1 (LANDMARK GRAPHICS CORPORATION) 02 May 2013 (2013-05-02) the whole document	1-15
A	WO 2006065915 A2 (SCHLUMBERGER CANADA LIMITED ET AL.) 22 June 2006 (2006-06-22) the whole document	1-15

☐ Further documents are listed in the continuation of Box C. ☑ See patent family annex.

* Special categories of cited documents:

- "A" document defining the general state of the art which is not considered to be of particular relevance
- "E" earlier application or patent but published on or after the international filing date
- "L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)
- "O" document referring to an oral disclosure, use, exhibition or other means
- "P" document published prior to the international filing date but later than the priority date claimed
- "T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
- "X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
- "Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art
- "&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
08 December 2015	**13 January 2016**

Name and mailing address of the ISA/CN	Authorized officer
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Facsimile No. **(86-10)62019451**	Telephone No. **(86-10)62413465**

INTERNATIONAL SEARCH REPORT
Information on patent family members

International application No.
PCT/CN2015/076928

Patent document cited in search report			Publication date (day/month/year)	Patent family member(s)			Publication date (day/month/year)
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				EP	2609540	A1	03 July 2013
				AU	2011293804	A1	14 March 2013
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				CA	2877373	A1	03 January 2014
				EP	2867460	A1	06 May 2015
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WO	2013062591	A1	02 May 2013	AU	2011379947	A1	17 April 2014
				US	9064066	B2	23 June 2015
				EP	2748739	A1	02 July 2014
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WO	2006065915	A2	22 June 2006	MX	2007006993	A	07 August 2007
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				CA	2728970	A1	22 June 2006
				CA	2590767	C	19 April 2011
				US	7684929	B2	23 March 2010
				EP	1825100	A2	29 August 2007
				US	7460957	B2	02 December 2008
				US	2006151214	A1	13 July 2006
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