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(54) Title: REAL-TIME DRILLING MONITORING

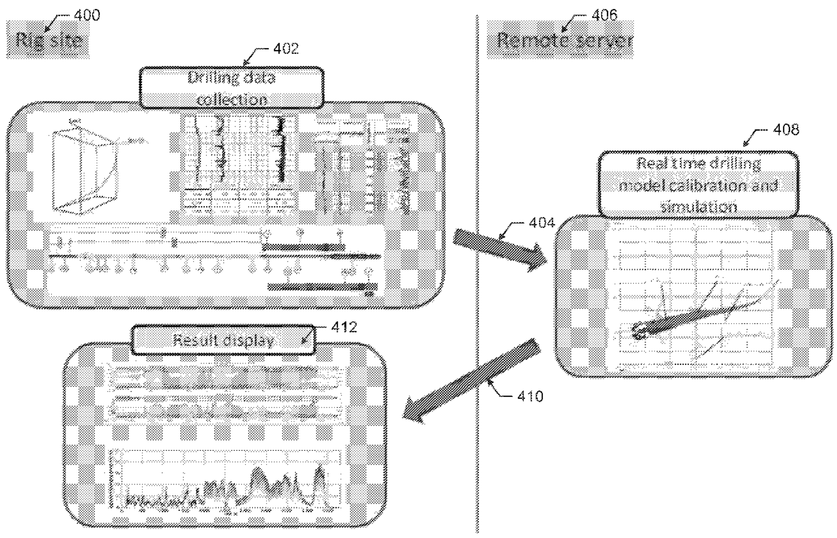

FIG. 4

(57) **Abstract**: A method, system, and computer readable medium for managing drilling operations include calibrating a drilling model using collected drilling data, and executing, during a drilling operation, a simulation on the drilling model to generate a predicted measurement value for a drilling property. During the drilling operation and from a drill string, an actual measurement value for the drilling property is obtained. Based on the actual measurement value matching the predicted measurement value, the simulation is extended to generated a simulated state of the drilling operation during the drilling operation, and a condition of the drilling operation detected. A notification may be presented based on the condition during the drilling operation.

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REAL-TIME DRILLING MONITORING

BACKGROUND

[0001] Computer simulation estimates the operations of a real-world system. Generally, computer simulation allows a user to test various control parameters to select an optimal control parameter. For example, in field management, computer simulation may be used to plan the drilling and production of valuable downhole assets. In particular, drilling simulation is used extensively to design drilling tools and plan for drilling operations.

SUMMARY

[0002] In general, in one aspect, embodiments relate to a method, system, and computer readable medium for managing drilling operations. Managing drilling operations include calibrating a drilling model using collected drilling data, and executing, during a drilling operation, a simulation on the drilling model to generate a predicted measurement value for a drilling property. During the drilling operation and from a drill string, an actual measurement value for the drilling property is obtained. Based on the actual measurement value matching the predicted measurement value, the simulation is extended to generated a simulated state of the drilling operation during the drilling operation, and a condition of the drill string detected. A notification may be presented based on the condition during the drilling operation.

[0003] Other aspects of the technology will be apparent from the following description and the appended claims.

BRIEF DESCRIPTION OF DRAWINGS

[0004] FIGs. 1, 2, 3, 4, and 5 show schematic diagrams in accordance with one or more embodiments of the technology.

[0005] FIGs. 6-16 show flowcharts in accordance with one or more embodiments of the technology.

DETAILED DESCRIPTION

[0006] Specific embodiments of the technology 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.

[0007] In the following detailed description of embodiments of the technology, numerous specific details are set forth in order to provide a more thorough understanding of the technology. However, it will be apparent to one of ordinary skill in the art that the technology 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.

[0008] 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 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.

[0009] In general, embodiments of the technology are directed to real-time management of drilling operations. In particular, a drilling model is calibrated. Simulations are continually performed on using the calibrated drilling model. A predicted measurement value from the simulations is compared against an actual measurement value acquired from the field. If the actual measurement value matches the simulated measurement value, then the simulations may be used to determine a simulated state of the drilling operation. Based on the simulated state, a condition of the drilling operation is determined and a notification of the condition presented.

[0010] One or more embodiments are directed to a drilling simulation-based real time system for drilling operation monitoring, diagnostics and optimization. In particular, one or more embodiments may perform diagnostics and optimization for drilling. For example, one or more embodiments may perform real-time vibration mitigation, real-time rate of penetration (ROP) optimization, real-time trajectory monitoring and directional drilling recommendation, real-time wellbore quality optimization, real-time logging while drilling/measurement while drilling (LWD/WMD) measurement quality assurance, real-time fatigue life monitoring, real-time bit-reamer load balancing, real-time bit and reamer wear monitoring, and real-time buckling and weight on bit (WOB) transfer monitoring.

[0011] Trajectory monitoring may include ensuring that trajectory is within a threshold of the desired planned direction. Wellbore quality is the degree of straightness of the hole. Fatigue life managing is managing stress on equipment, such as when rotating while drilling the hole. One or more embodiments may detect and manage the remaining amount of life of each part of equipment. Bit reamer load balancing is managing an amount the reamer expands as compared to the amount that the bit cuts. Bit and reamer wear monitoring may include detecting and managing when the cutters go blunt. Buckling and weight on bit transfer monitoring may include managing when cutters go blunt, and preventing or managing deformation of the drill pipes.

[0012] 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.

[0013] 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 just 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.

[0014] 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, as shown in FIG. 1, 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.

[0015] 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.

[0016] 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.

[0017] 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.

[0018] 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.

[0019] During a drilling operation, 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.

[0020] 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. 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'.

[0021] 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.

[0022] 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 equipment 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.

[0023] 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. For example, the sensors may include one or more of a camera, a pressure sensor, a temperature sensor, a flow rate sensor, a vibration sensor, a current sensor, a voltage sensor, a resistance sensor, a gesture detection sensor or device, a voice actuated or recognition device or sensor, or other suitable sensors. Example down hole drill string sensors include functionality to obtain drilling dynamics measurements, such as tri-axis accelerations, collar rotations per minute (RPM) and stick-slip, bending moment, down hole torque, and axial weight. Sensors that perform measurement while drilling and logging while drilling may include functionality to perform caliper logging, acquire annulus pressure and equivalent circulating density (ECD) measurements, perform a well survey, acquire shock and vibration measurements, and obtain formation information at the drilling depths and ahead of bit. The information collected by the sensors and cameras is conveyed to the various parts of the drilling system and/or the surface control unit.

[0024] At the rig floor or the surface, the sensors may include functionality to obtain input drilling parameters (e.g., Source RPM (SRPM) (actual table revolution), rotating/sliding, rotary steerable system (RSS) steering ratio and through flowline (TF), weight on bit (WOB) and hookload, and flow rate and MW), surface drilling measurements (e.g., surface torque, stand pipe pressure, top drive block location/feeding speed (ROP)), and mud logging (e.g., cuttings, and formation type and unconfined compression strength (UCS)).

[0025] FIG. 2 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 (200) and a field management tool (220) for accessing fluid in the target reservoir through a bore hole (250) of a directional well (217). The wellsite drilling system (200) includes various components (*e.g.*, drill string (212), annulus (212), bottom hole assembly (BHA) (214), Kelly (215), mud pit (216), etc.) as generally described with respect to the wellsite drilling systems (100) (*e.g.*, drill string (115), annulus (126), bottom hole assembly (BHA) (120), 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 (217). Accordingly, special tools or techniques may be used to ensure that the path along the bore hole (250) reaches the particular location of the target reservoir (200).

[0026] For example, the BHA (214) may include sensors (208), rotary steerable system (209), and the bit (210) 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 (217) 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 (201), (202), (202), (204)) corresponding to the multiple layers in the subterranean formation. For example, certain sections (*e.g.*, sections (201) and (202)) may use cement (207) reinforced casing (206) due to the particular formation compositions, geophysical characteristics, and geological conditions.

[0027] Further as shown in FIG. 2, surface unit (211) (as generally described with respect to the surface unit (124) of FIG. 1) may be operatively linked to the wellsite drilling system (200) and the field management tool (220) via communication links (218). The surface unit (211) may be configured with functionalities to control and monitor the drilling activities by sections in real-time via the communication links (218). The field management tool (220) 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 (218) according to a drilling operation workflow. The communication link (218) may comprise the communication subassembly (252) as described with respect to FIG. 1 above.

[0028] 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.

[0029] 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.

[0030] 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 the entire oilfield. Various combinations of these and other oilfield simulators may be provided.

[0031] FIG. 3 shows an example of a communication structure in accordance with one or more embodiments of the technology. As shown in FIG. 3, downhole sensors (300) may transmit data (302) via the communication link to a surface unit (304). Similarly, rig surface data (306) may also be transmitted to surface unit (304). The surface unit may provide the data to a simulation server (308). For example, the simulation server (308) may execute the field management tool, discussed above.

[0032] As shown in FIG. 3, real time information is obtained from the wellsite as part of data acquisition and monitoring. Further, wellbore and reservoir information may be gathered. The surface unit may compile the gathered information and send the information to the simulation server. For example, the surface unit may interface with the controller for each item of equipment to gather and compile the information. When gathering the information, sensors might not be located along the entire length of the drill string, but rather a few positions may have measurement values. In such a scenario, when the simulator receives the gathered information, the simulator may provide an estimation as to the remaining positions. The simulator may include functionality to generate dynamics simulation model, calibrate and re-calibrate the model using real-time data, execute the calibrated model, monitor variables through simulation, identify and warn of dangerous conditions, and explore parameters to mitigate adverse drilling dynamics. The simulator may provide simulation results to the surface unit, which displays the simulation results and event warnings.

[0033] Variables monitoring and diagnostics may include monitoring drilling efficiency (e.g., cutting structure compatibility (bit reamer balance) and bit wear), drilling stability (e.g., vibration levels along BHA, damaging vibration mode (whirling, stick-slip), neutral point), robustness (e.g., cumulative fatigue of drill string, drill string buckling, and overloading detection (predicted stress versus tool strength data), measurement quality (e.g., survey rectification accounting for BHA sag, collar lateral displacement at MWD sensors), borehole quality (e.g., hole tortuosity / hole microDLS / hole spiraling, and hole size variation), directional tendency (e.g., Steering parameter sensitivity (WOB, SR, Cycle, FLOW, sliding/rotating distance) and other aspects of drilling (e.g., motor TF rectification accounting for drillstring twist, stuck point depth estimation, and jarring impact). The system may perform warning and advising to the drilling process including, pulling out of hole (POOH) based on high cumulative fatigue and severe cutting structure wear. The system may recommend to pull off bottom based on damaging whirling motion detected, excessive drill string buckling detected. The system may recommend a drilling parameter change based on high lateral/axial/torsional vibrations detected, poor borehole quality, challenging formation drilling (formation information based on LWD, mud logging, and the look-ahead detection of LWD), poor directional control, poor weight distribution between bit and reamer, an undesired neutral point depth, and mild drillstring buckling.

[0034] FIG. 4 shows an example schematic diagram of a system showing flow in accordance with one or more embodiments of the technology. As shown in FIG. 4, at the rig site (400) of the drilling rig, drilling data may be collected (402). The drilling data may be transferred (404) to remote server (406), such as the field management tool. The remote server may perform real-time drilling model calibration and simulation (408). Results of the simulation may be transferred (410) to the rig site (400) for display (412).

[0035] In one or more embodiments, the field management tool 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. 5, the computing system (500) may include one or more computer processor(s) (502), associated memory (504) (*e.g.*, random access memory (RAM), cache memory, flash memory, *etc.*), one or more storage device(s) (506) (*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) (502) 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 (500) may also include one or more input device(s) (510), such as a touchscreen, keyboard, mouse, microphone, touchpad, electronic pen, or any other type of input device. Further, the computing system (500) may include one or more output device(s) (508), 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 (500) may be connected to a network (512) (*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 (512)) connected to the computer processor(s) (502), memory (504), and storage device(s) (506). Many different types of computing systems exist, and the aforementioned input and output device(s) may take other forms.

[0036] Software instructions in the form of computer readable program code to perform embodiments of the technology 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 technology.

[0037] 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 technology may be implemented on a distributed system having a plurality of nodes, where each portion of the technology may be located on a different node within the distributed system. In one embodiment of the technology, 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.

[0038] 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.

[0039] FIGs. 6-16 show example flowcharts in accordance with one or more embodiments of the technology. While the various blocks in this flowchart are presented and described sequentially, one of ordinary skill will appreciate that some of the blocks may be executed in different orders, may be combined or omitted, and some of the blocks may be executed in parallel. Furthermore, the blocks may be performed actively or passively. For example, some blocks may be performed using polling or be interrupt driven in accordance with one or more embodiments of the technology. By way of an example, determination blocks 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 technology. As another example, determination blocks 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 technology.

[0040] Further, although the flowcharts show certain blocks as being performed by the rig computing device (or rig PC in FIGs. 6-16) and other blocks being performed by the remote server, different allocations may be used. For example, all blocks may be performed by the remote server and none by the rig computing device, or all blocks performed by the rig computing device and none by the remote server. By way of another example, one or more blocks of the Figures that are designated as being performed by the remote server may be performed by the rig computing device. Other allocations may be used without departing from the scope of the technology.

[0041] FIG. 6 shows an example flowchart (600) to calibrate a model in accordance with one or more embodiments of the technology. In particular, as generally shown in FIG. 6, the drilling model is calibrated to match actual drilling conditions. In one or more embodiments of the technology, using a calibrated model, during a drilling operation, a simulation on the drilling model is performed to generate a predicted measurement value for a drilling property. An actual measurement value is obtained from the sensors for the drilling property. If the actual measurement value matches the predicted measurement value from simulations, the simulation is extended during the drilling operation to generate a simulated state of the drilling operation. A condition of the drilling operation may be detected based on the simulated state and presented as discussed above. Thus, simulations may be continuously performed on a calibrated drilling model to determine the state of the drill string and detect when a condition exists that should be rectified. Periodic recalibrations may be performed by adjusting model parameters when the predicted measurement value is not within a threshold of the actual measurement value for at least one position of the drillstring.

[0042] FIGs. 7-16 show example flowcharts for testing particular conditions. In particular, FIG. 7 shows a flowchart (700) for fatigue and overflow monitoring. In FIG. 7, fatigue for a segment may be a particular equipment part or an entire segment of the drill string. Maximum stress may be determined, for example, based on equipment manufacturer's guidelines.

[0043] FIG. 8 shows a flowchart (800) for vibration monitoring and diagnostics in accordance with one or more embodiments of the technology. For example, the blocks in FIG. 8 may be used to monitor shock and vibration. Such shock and vibration may be caused by damaging, rolling and stick sleeve. FIG. 9 shows a flowchart (900) for drill string buckling and neutral point monitoring in accordance with one or more embodiments of the technology. FIG. 10 shows a flowchart (1000) for cutting structure force monitoring in accordance with one or more embodiments of the technology. FIG. 11 shows a flowchart (1100) for measurement quality monitoring in accordance with one or more embodiments of the technology. FIG. 12 shows a flowchart (1200) for borehole quality monitoring in accordance with one or more embodiments of the technology. FIG. 13 shows a flowchart (1300) for jarring process monitoring in accordance with one or more embodiments of the technology.

[0044] FIG. 14 shows a flowchart (1400) for motor TF compensation in accordance with one or more embodiments of the technology. The objective of the motor TF compensation module is to help the directional driller (DD) choose the right tool face offset before going on bottom. DD may request help before going on bottom. While on bottom, the system may obtain actual data and calibrate the drilling model to be ready for next DD request. Output to the DD may be tool face as a function of flow and WOB.

[0045] FIG. 15 shows a flowchart (1500) for steering parameter selection in accordance with one or more embodiments of the technology. Steering parameter selection may apply to RSS or motor drilling. The steering parameter selection suggests to the DD what steering parameters should be used to achieve the trajectory or DLS. The steering parameter selection may be applied real time or at the start of each stand and may include steering parameter, such as SR steering ratio, WOB, RPM, Drilling cycle, and steering vs neutral distance.

[0046] FIG. 16 shows a flowchart (1600) for drilling parameter optimization and recommendation in accordance with one or more embodiments of the technology. In the planning phase, drilling plan is generated. However, the drilling plan is based on certain formation, certain friction coefficient and steering parameters that may or may not be similar to actual well. The drilling parameter optimization and recommendation in FIG. 16 is performed real time during the drilling process. In other words, the rock parameters and friction are computed/calibrated using real time data. After calibration, the system may be used to understand the effects of changing drilling parameters.

[0047] While the technology 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 technology as disclosed herein. Accordingly, the scope of the technology should be limited only by the attached claims.

CLAIMS

What is claimed is:

1. A method for managing drilling operations comprising:
   calibrating a drilling model using collected drilling data;
   executing, during a drilling operation, a simulation on the drilling model to generate a predicted measurement value for a drilling property;
   obtaining, during the drilling operation and from a drill string, an actual measurement value for the drilling property;
   extending the simulation during the drilling operation, based on the actual measurement value matching the predicted measurement value, to generate a simulated state of the drilling operation;
   detecting, during the drilling operation, a condition of the drilling operation based on the simulated state; and
   presenting a notification based on the condition during the drilling operation.

2. The method of claim 1, wherein detecting the condition comprises detecting vibration of the drill string based on the simulated state of the drilling operation.

3. The method of claim 1, further comprising:
   determining, during the drilling operation, an optimal setting for a rate of penetration of the drill string,
   wherein detecting the condition comprises determining that the optimal setting fails to match an estimated rate of penetration,
   wherein presenting the notification comprises presenting the optimal setting based on the estimated rate of penetration failing to match the optimal setting.

4. The method of claim 1, wherein detecting the condition comprises determining that the actual trajectory of a well bore based on the simulated state of the drilling

operation fails to match a planned trajectory, and wherein the method further comprises:

selecting a setting to adjust the actual trajectory to match the planned trajectory, wherein presenting the notification comprises presenting the setting.

5. The method of claim 1, wherein detecting the condition comprises determining that a shape of a well bore fails to satisfy a quality threshold, and wherein the method further comprises:

selecting a setting to adjust the shape of the well bore to match the quality threshold, wherein presenting the notification comprises presenting the setting.

6. The method of claim 1, wherein detecting the condition comprises determining that a collection of drilling data fails to satisfy a quality threshold for a plurality of measurements, and wherein the method further comprises:

selecting a setting to adjust the collection of data to satisfy the quality threshold, wherein presenting the notification comprises presenting the setting.

7. The method of claim 1, further comprising:

calculating an estimated amount of fatigue of a part of the drill string using on the simulated state,

wherein detecting the condition comprises

comparing the estimated amount of fatigue with a maximal fatigue for the part to obtain a remaining life of the part, and

determining that the remaining life fails to satisfy a threshold,

wherein presenting the notification comprises presenting an alert to rectify the part.

8. The method of claim 1, further comprising:

determining, during the drilling operation, an optimal bit reamer load balancing setting, wherein detecting the condition comprises determining that the optimal bit reamer load balancing setting fails to match an estimated bit reamer load balancing,

wherein presenting the notification comprises presenting the optimal bit reamer load balancing setting based on the estimated rate on bit failing to match the optimal setting.

9. The method of claim 1, wherein detecting a condition comprises detecting a buckling of the drill string, and presenting the notification comprises presenting a setting to address the bucking.

10. The method of claim 1, further comprising

    collecting the drilling data from a plurality of sensors located along the drillstring.

11. The method of claim 1, wherein the drilling model is further calibrated with a subsurface model.

12. A system for managing drilling operations comprising:

    a surface unit that:

        collects an actual measurement value from a drill string during a drilling operation, and

        presents a notification based on a condition detected during the drilling operation; and

    a simulation server that:

        calibrates a drilling model using collected drilling data,

        executes, during a drilling operation, a simulation on the drilling model to generate a predicted measurement value for a drilling property,

        obtains, during the drilling operation and from the surface unit, the actual measurement value for the drilling property, extends the simulation during the drilling operation, based on the actual measurement value matching the predicted measurement value, to generate the simulated state of the drilling operation, and

detects, during the drilling operation, a condition of the drilling operation based on the simulated state.

13. The system of claim 12, further comprising:

the drill string comprising a plurality of sensors for acquiring the actual measurement values, the drill string for drilling a wellbore.

14. A non-transitory computer readable medium for managing drilling operations, the non-transitory computer readable medium comprising computer readable program code for:

calibrating a drilling model using collected drilling data;

executing, during a drilling operation, a simulation on the drilling model to generate a predicted measurement value for a drilling property;

obtaining, during the drilling operation and from a drill string, an actual measurement value for the drilling property;

extending the simulation during the drilling operation, based on the actual measurement value matching the predicted measurement value, to generate a simulated state of the drilling operation;

detecting, during the drilling operation, a condition of the drilling operation based on the simulated state; and

presenting a notification based on the condition during the drilling operation.

15. The non-transitory computer readable medium of claim 14, wherein detecting the condition comprises detecting vibration of the drill string based on the simulated state of the drilling operation.

16. The non-transitory computer readable medium of claim 14, further comprising computer readable program code for:

determining, during the drilling operation, an optimal setting for a rate of penetration of the drill string,

wherein detecting the condition comprises determining that the optimal setting fails to match an estimated rate of penetration,

wherein presenting the notification comprises presenting the optimal setting based on the estimated rate of penetration failing to match the optimal setting.

17. The non-transitory computer readable medium of claim 14, wherein detecting the condition comprises determining that the actual trajectory of a well bore based on the simulated state of the drilling operation fails to match a planned trajectory, and wherein the non-transitory computer readable medium further comprises computer readable program code for:

selecting a setting to adjust the actual trajectory to match the planned trajectory, wherein presenting the notification comprises presenting the setting.

18. The non-transitory computer readable medium of claim 14, wherein detecting the condition comprises determining that a shape of a well bore fails to satisfy a quality threshold, and wherein the non-transitory computer readable medium further comprises computer readable program code for:

selecting a setting to adjust the shape of the well bore to match the quality threshold, wherein presenting the notification comprises presenting the setting.

19. The non-transitory computer readable medium of claim 14, wherein detecting the condition comprises determining that a collection of drilling data fails to satisfy a quality threshold for a plurality of measurements, and wherein the non-transitory computer readable medium further comprises computer readable program code for:

selecting a setting to adjust the collection of data to satisfy the quality threshold, wherein presenting the notification comprises presenting the setting.

20. The non-transitory computer readable medium of claim 14, further comprising computer readable program code for:

calculating an estimated amount of fatigue of a part of the drill string using on the simulated state,

wherein detecting the condition comprises

comparing the estimated amount of fatigue with a maximal fatigue for the part to obtain a remaining life of the part, and

determining that the remaining life fails to satisfy a threshold,

wherein presenting the notification comprises presenting an alert to rectify the part.

21. The non-transitory computer readable medium of claim 14, further comprising computer readable program code for:

determining, during the drilling operation, an optimal bit reamer load balancing setting,

wherein detecting the condition comprises determining that the optimal bit reamer load balancing setting fails to match an estimated bit reamer load balancing,

wherein presenting the notification comprises presenting the optimal bit reamer load balancing setting based on the estimated rate on bit failing to match the optimal setting.

22. The non-transitory computer readable medium of claim 14, wherein detecting a condition comprises detecting a buckling of the drill string, and presenting the notification comprises presenting a setting to address the bucking.

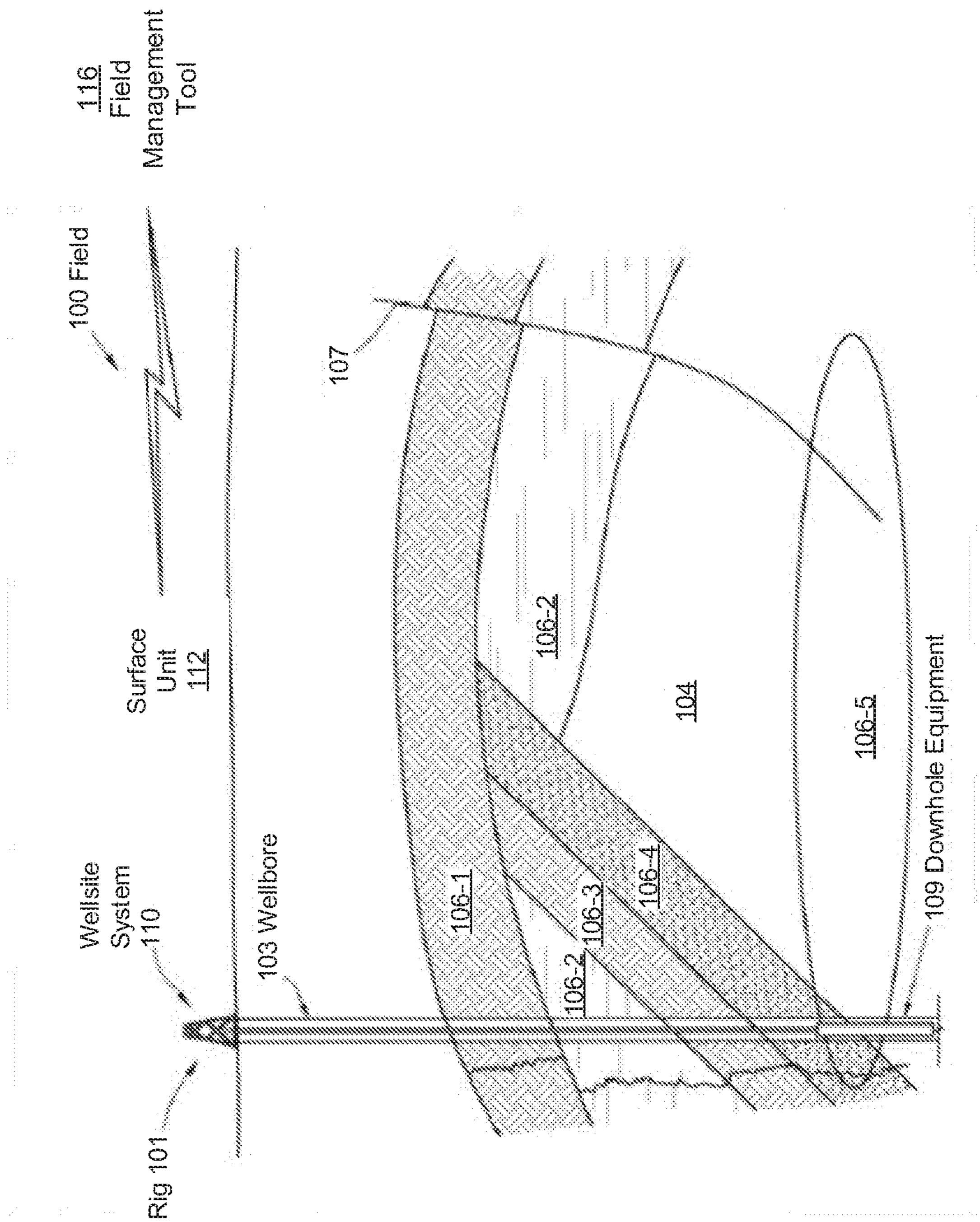
116
Field
Management
Tool
100 Field
Surface
Unit
112
107
106-2
104
106-5
109 Downhole Equipment
106-4
106-1
106-3
106-2
103 Wellbore
Wellsite
System
110
Rig 101

FIG. 1

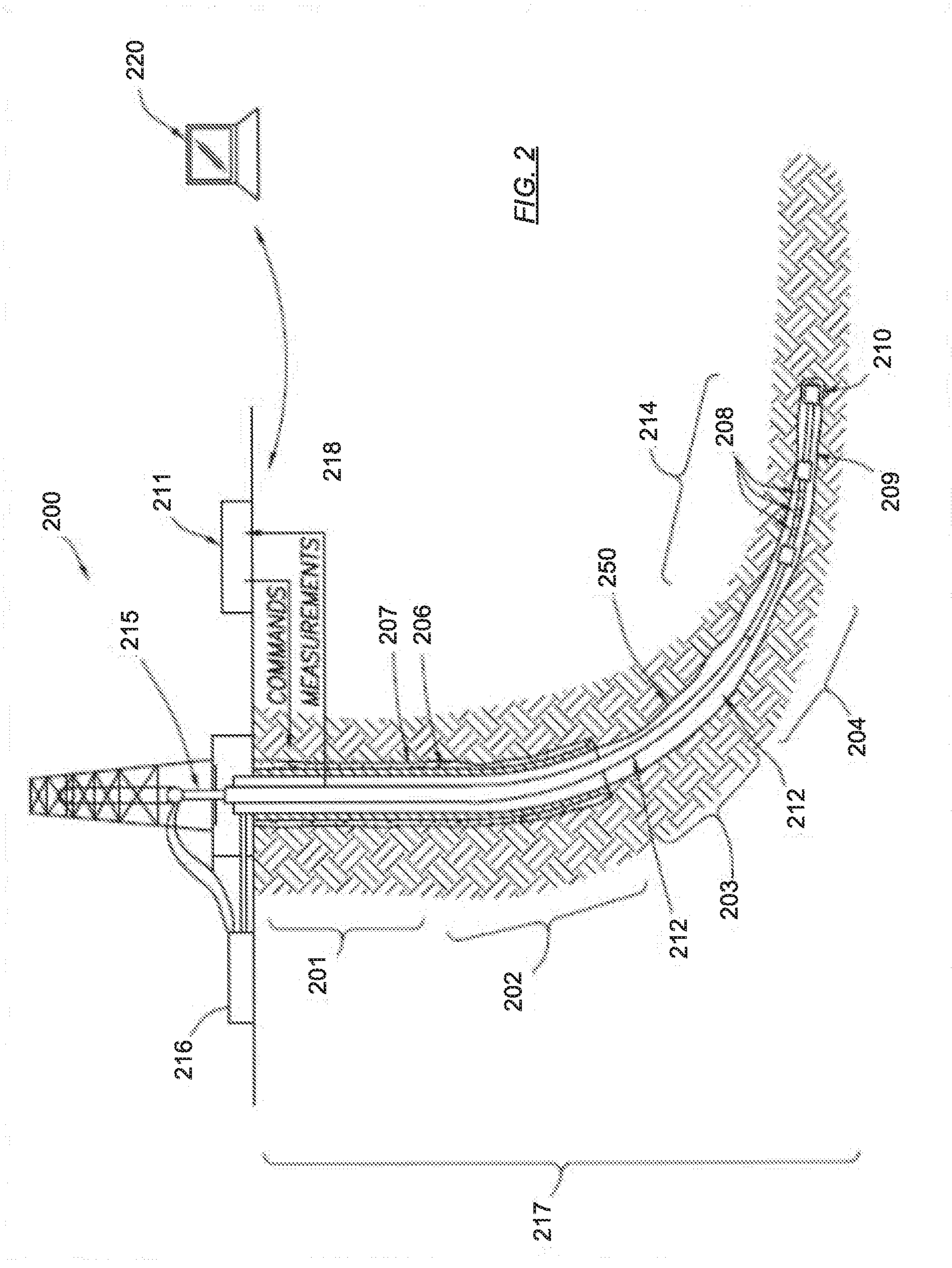
200
211
215
216
218
220
COMMANDS
MEASUREMENTS
201
202
203
204
206
207
208
209
210
212
212
214
217
250

FIG. 2

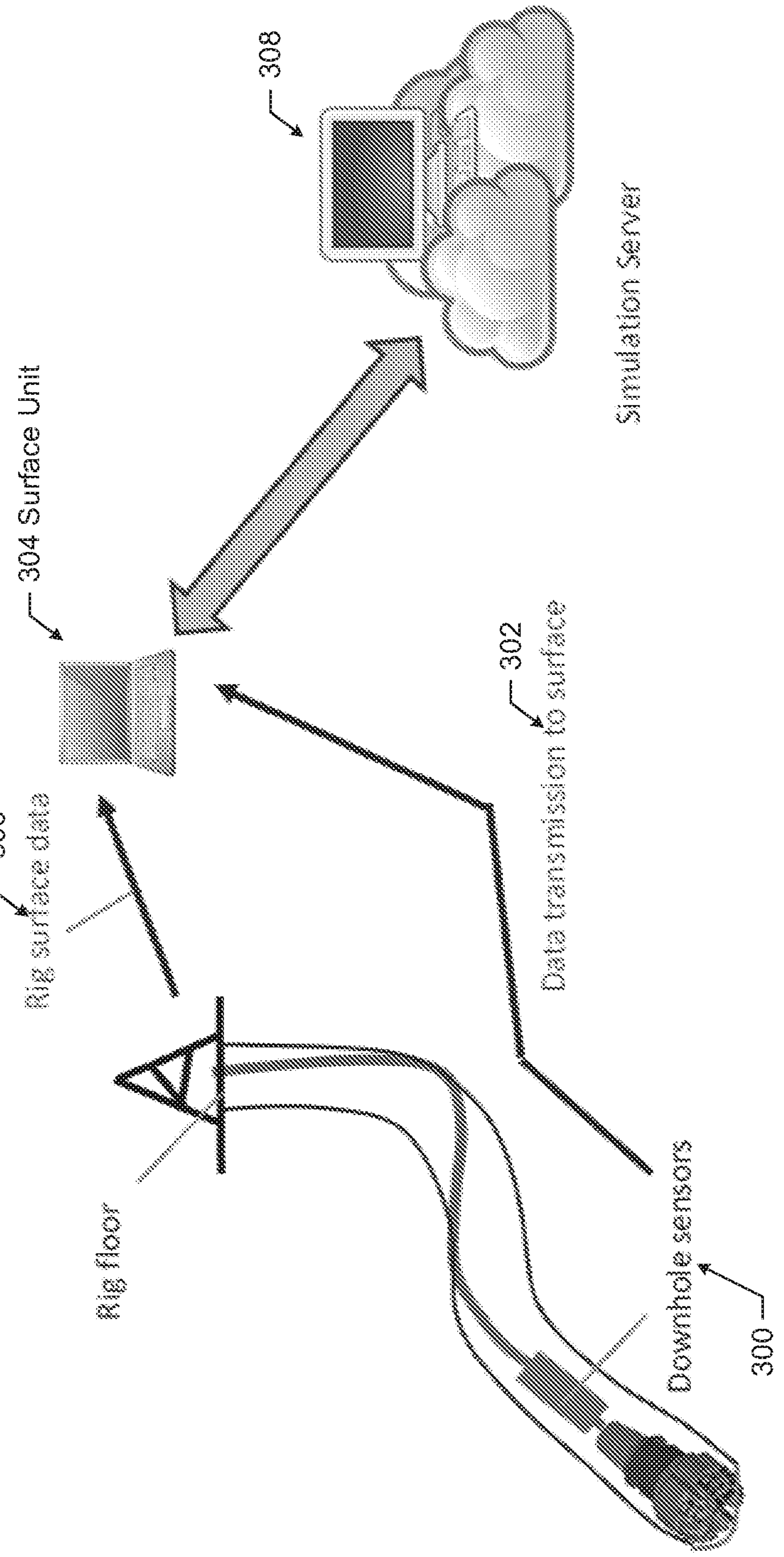
308
Simulation Server
304 Surface Unit
302
Data transmission to surface
306
Rig surface data
Rig floor
Downhole sensors
300

FIG. 3

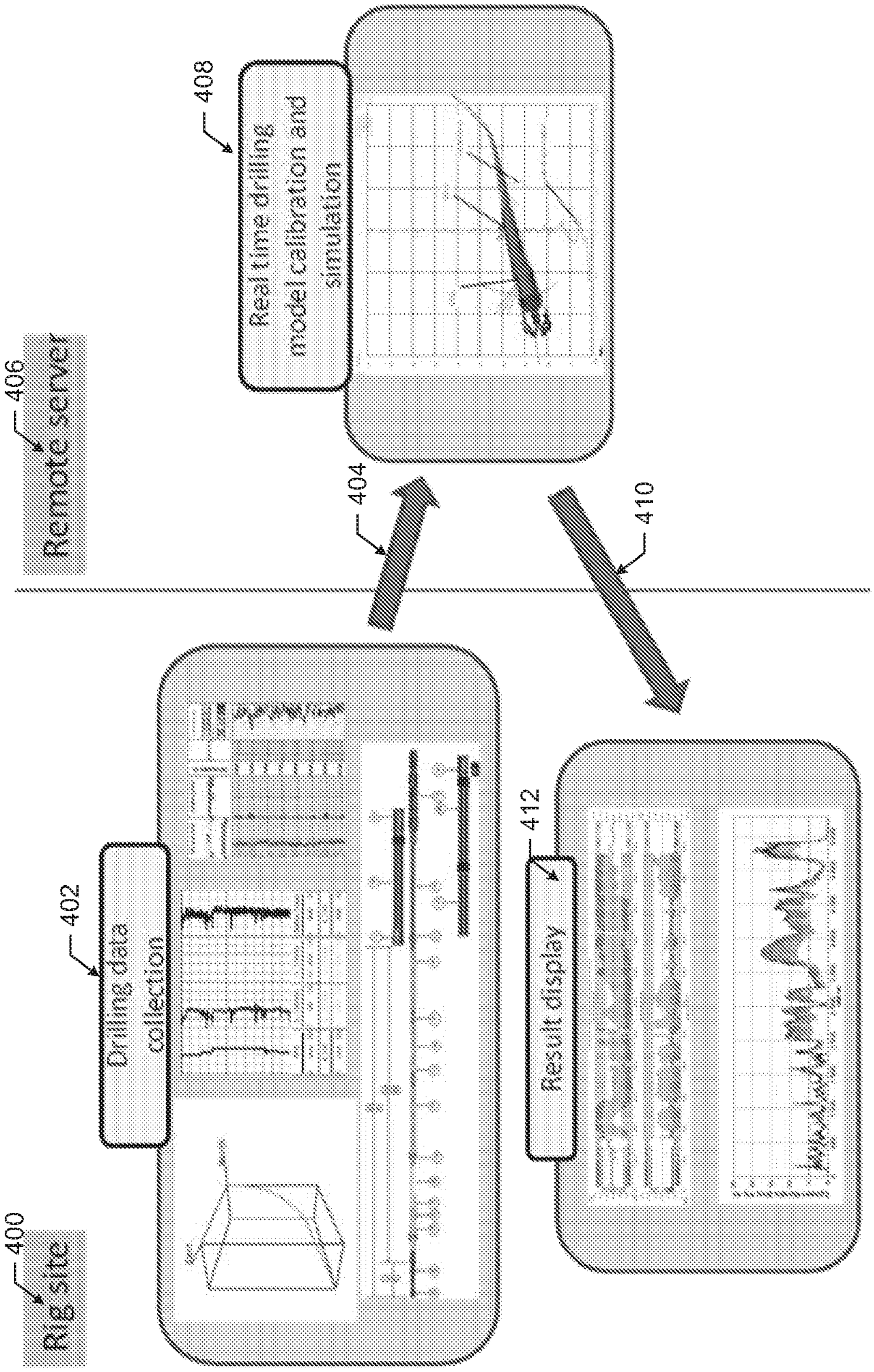
400
Rig site
402
Drilling data collection
404
406
Remote server
408
Real time drilling model calibration and simulation
410
412
Result display

FIG. 4

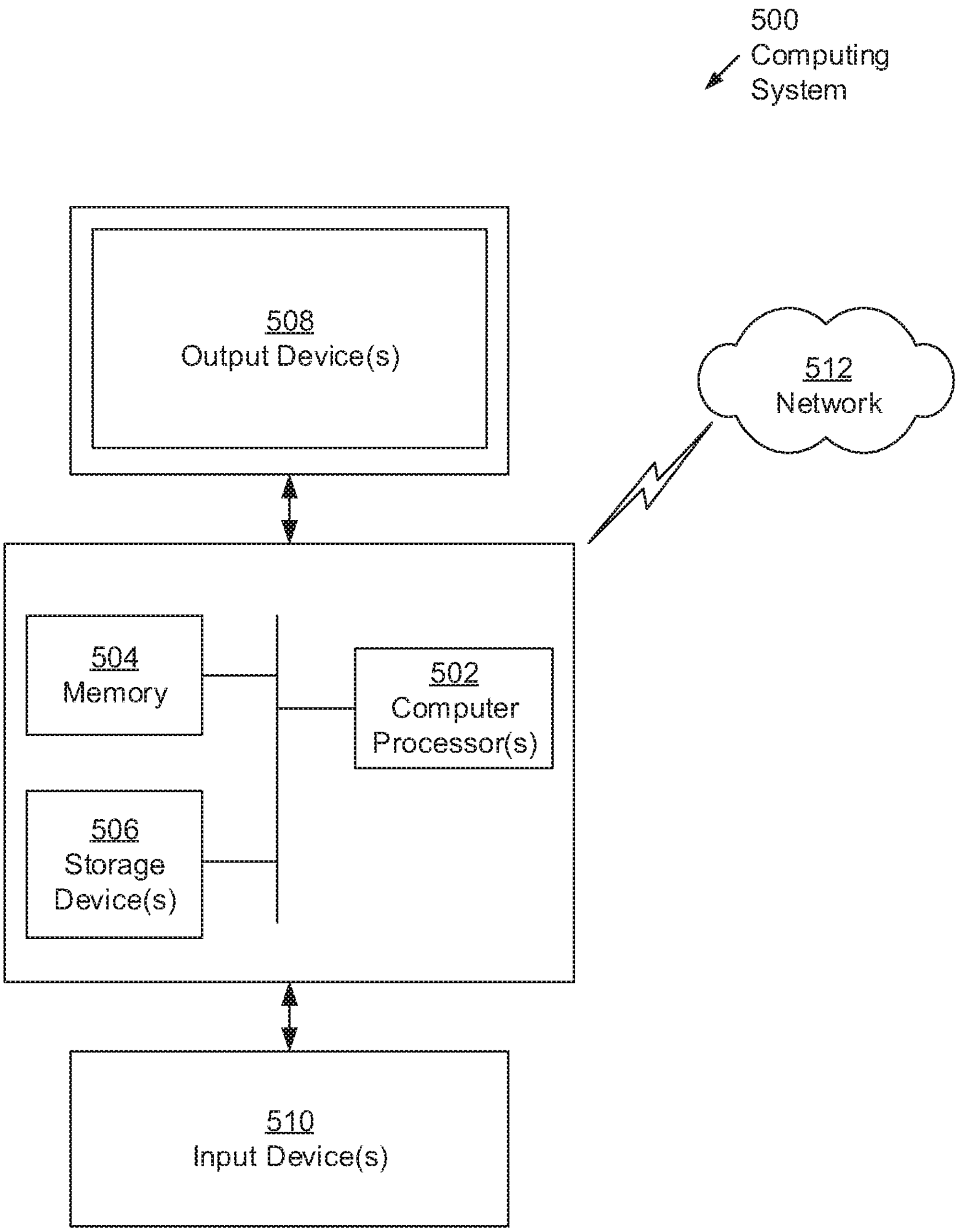
500
Computing
System
508
Output Device(s)
512
Network
504
Memory
502
Computer
Processor(s)
506
Storage
Device(s)
510
Input Device(s)

FIG. 5

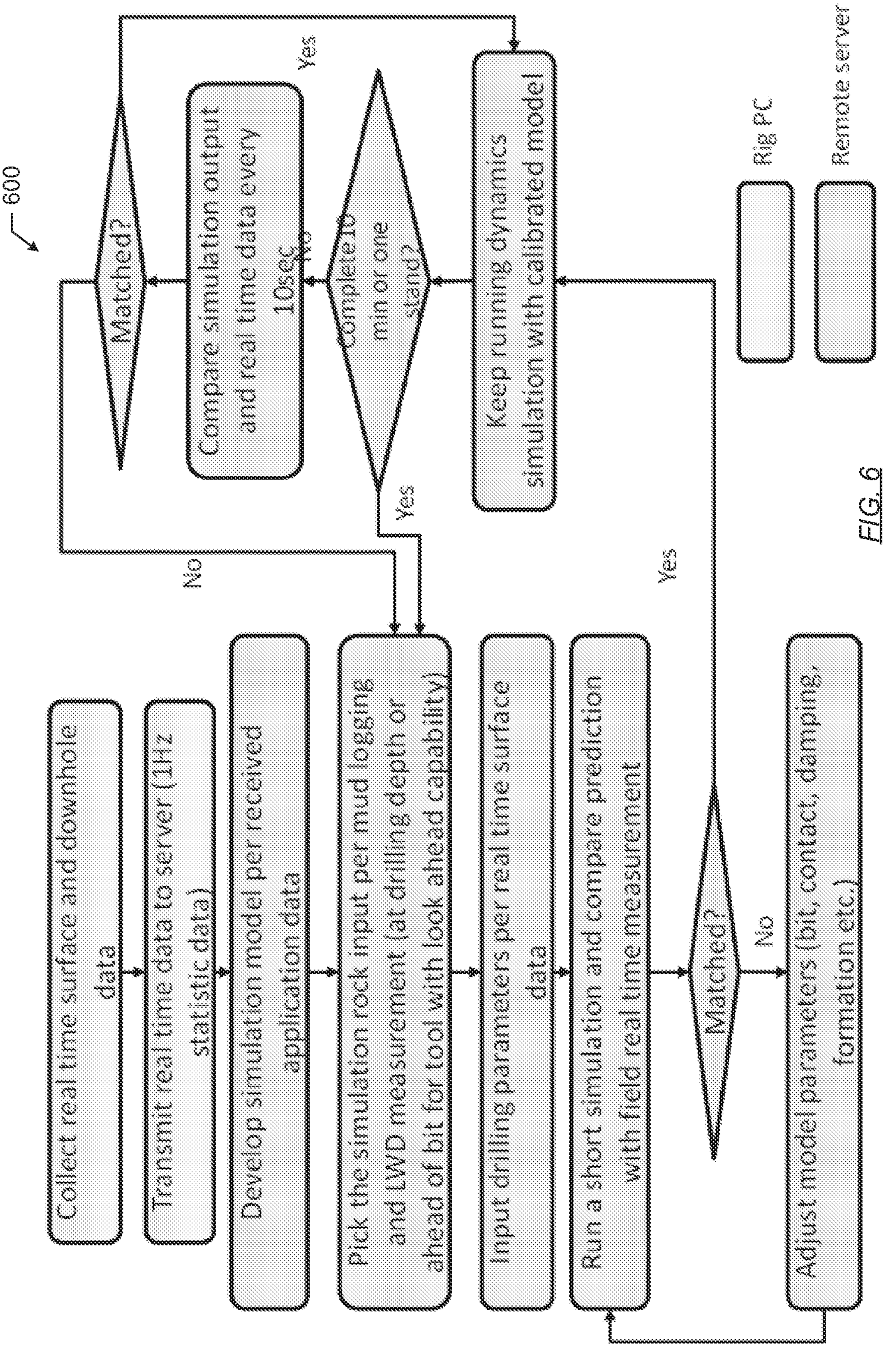
600
Collect real time surface and downhole data
Transmit real time data to server (1Hz statistic data)
Develop simulation model per received application data
Pick the simulation rock input per mud logging and LWD measurement (at drilling depth or ahead of bit for tool with look ahead capability)
Input drilling parameters per real time surface data
Run a short simulation and compare prediction with field real time measurement
Matched?
No
Adjust model parameters (bit, contact, damping, formation etc.)
Yes
Keep running dynamics simulation with calibrated model
Complete 10 min or one stand?
No
Yes
Compare simulation output and real time data every 10sec
Matched?
Yes
No
Rig PC
Remote server

FIG. 6

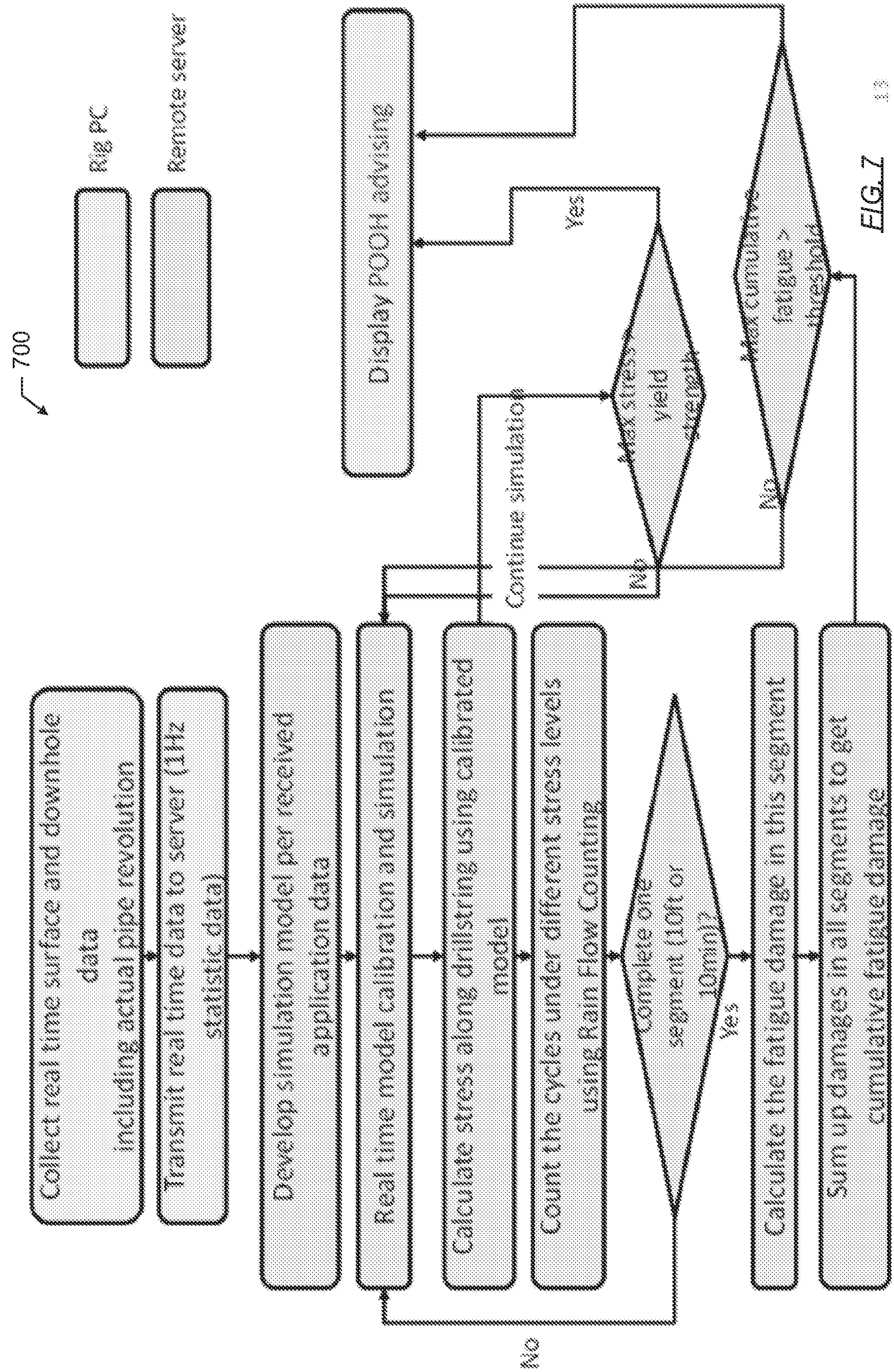
700
Rig PC
Remote server
Collect real time surface and downhole data including actual pipe revolution data
Transmit real time data to server (1Hz statistic data)
Develop simulation model per received application data
Real time model calibration and simulation
Calculate stress along drillstring using calibrated model
Count the cycles under different stress levels using Rain Flow Counting
Complete one segment (10ft or 10min)?
Yes
No
Calculate the fatigue damage in this segment
Sum up damages in all segments to get cumulative fatigue damage
Continue simulation
yield
Yes
No
fatigue >
No
Display POOH advising

FIG. 7

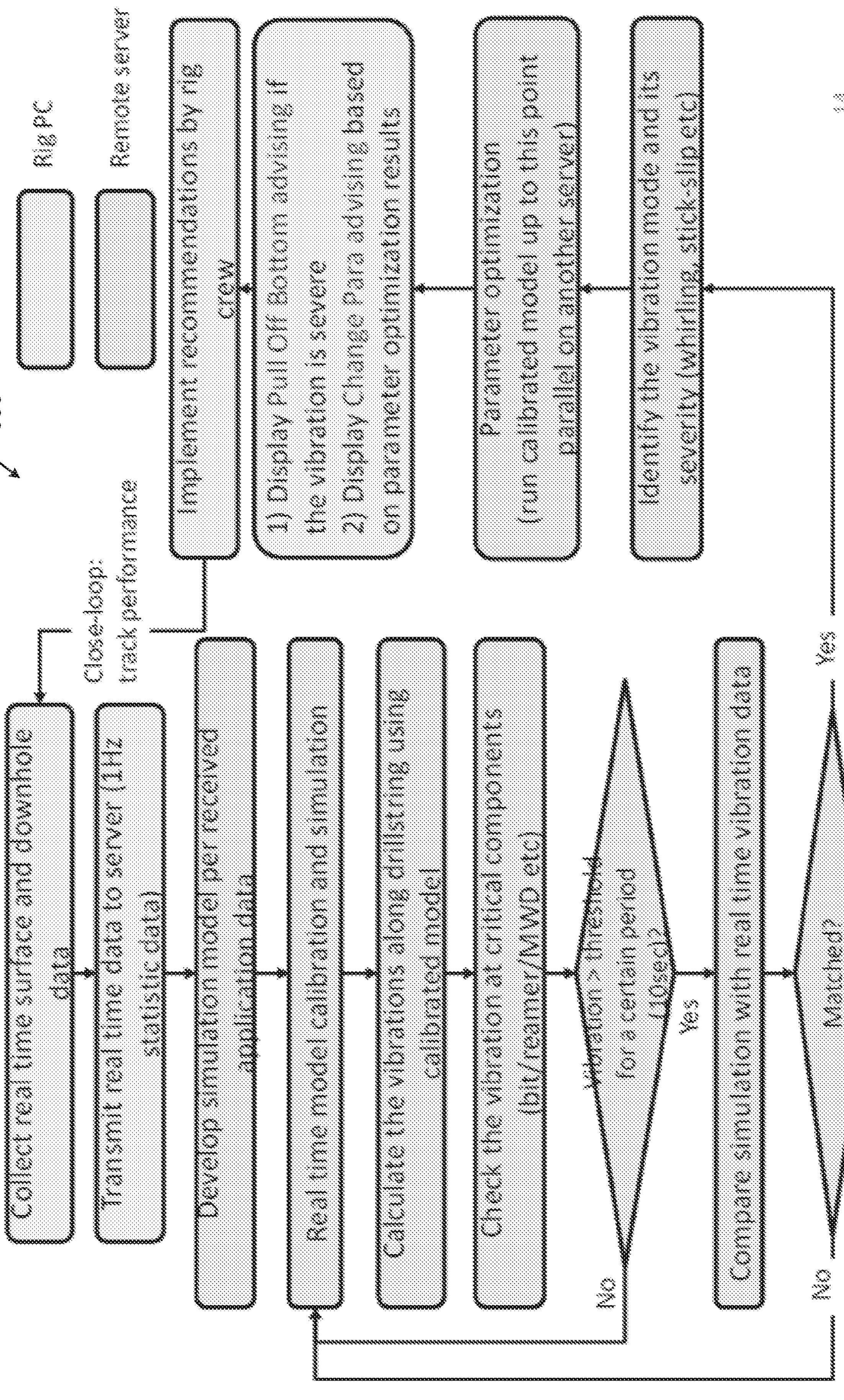
800
Rig PC
Remote server
Collect real time surface and downhole data
Transmit real time data to server (1Hz statistic data)
Develop simulation model per received application data
Real time model calibration and simulation
Calculate the vibrations along drillstring using calibrated model
Check the vibration at critical components (bit/reamer/MWD etc)
Vibration > threshold for a certain period (10sec)?
No
Yes
Compare simulation with real time vibration data
Matched?
No
Yes
Identify the vibration mode and its severity (whirling, stick-slip etc)
Parameter optimization (run calibrated model up to this point parallel on another server)
1) Display Pull Off Bottom advising if the vibration is severe
2) Display Change Para advising based on parameter optimization results
Implement recommendations by rig crew
Close-loop: track performance

FIG. 8

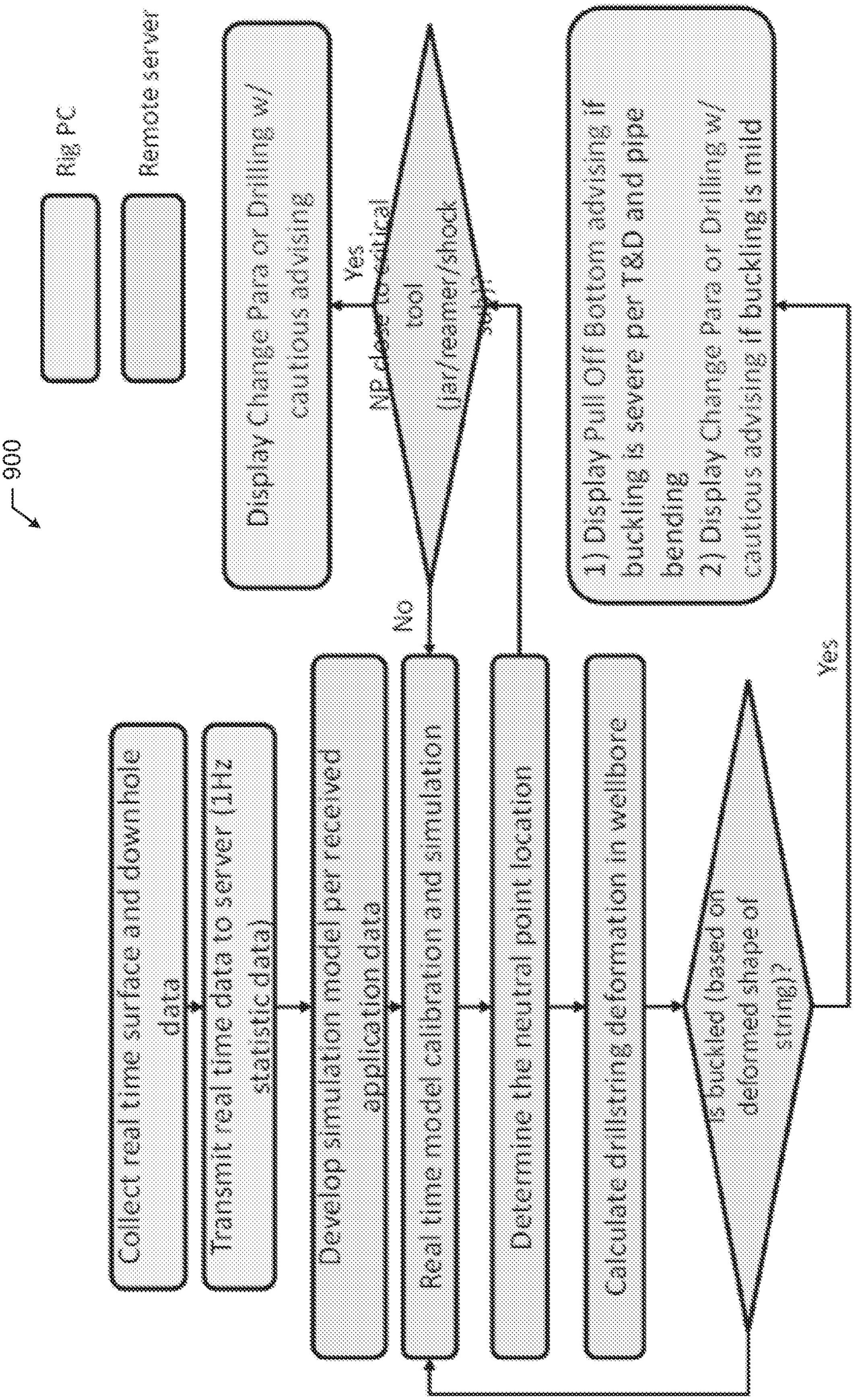
900
Rig PC
Remote server
Collect real time surface and downhole data
Transmit real time data to server (1Hz statistic data)
Develop simulation model per received application data
Real time model calibration and simulation
Determine the neutral point location
Calculate drillstring deformation in wellbore
Is buckled (based on deformed shape of string)?
Yes
1) Display Pull Off Bottom advising if buckling is severe per T&D and pipe bending
2) Display Change Para or Drilling w/ cautious advising if buckling is mild
NP close to critical tool (jar/reamer/shock sub)?
Yes
Display Change Para or Drilling w/ cautious advising
No

FIG. 9

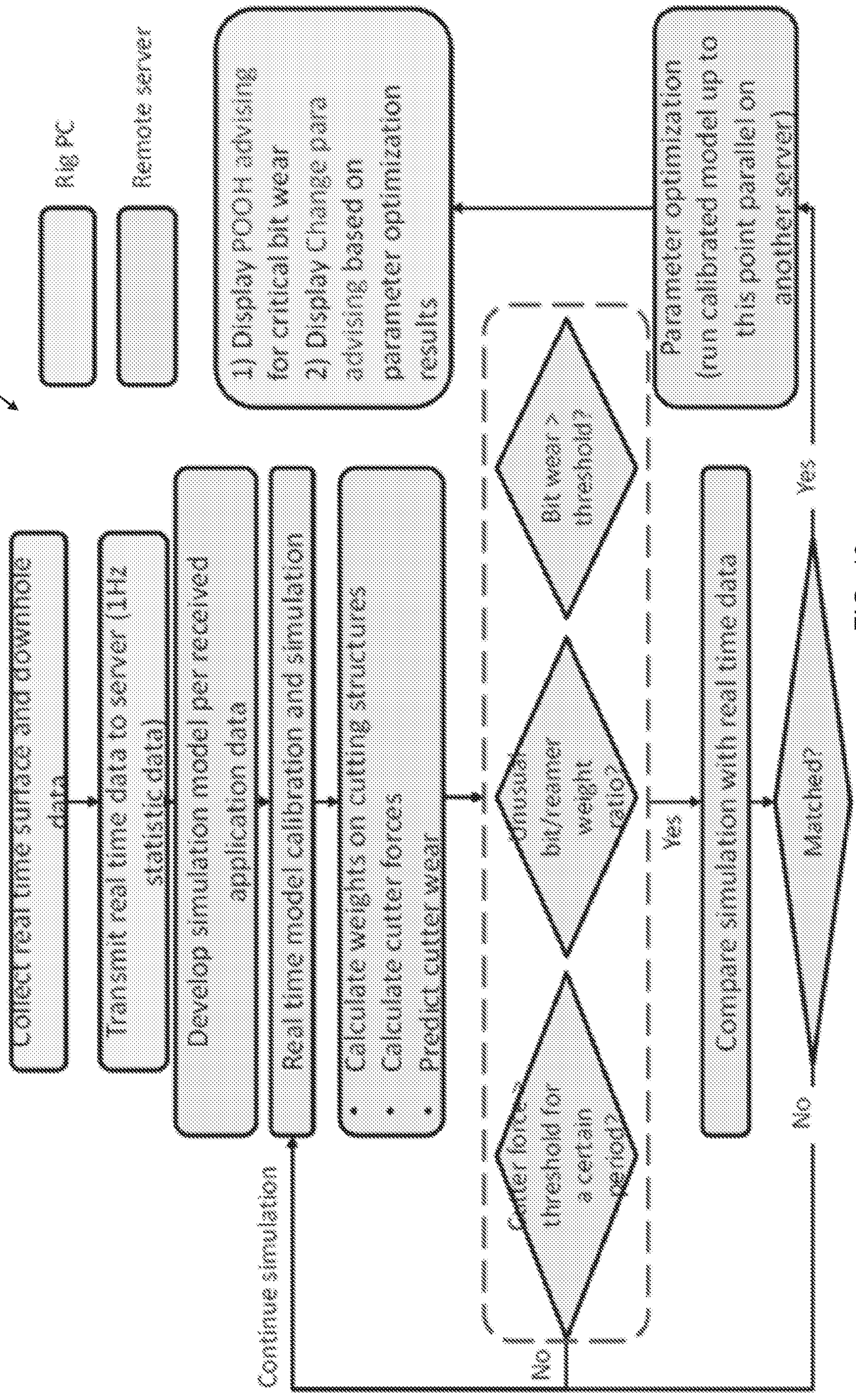
1000
Rig PC
Remote server
Collect real time surface and downhole data
Transmit real time data to server (1Hz statistic data)
Develop simulation model per received application data
Real time model calibration and simulation
• Calculate weights on cutting structures
• Calculate cutter forces
• Predict cutter wear
Cutter force > threshold for a certain period?
Unusual bit/reamer weight ratio?
Bit wear > threshold?
No
Continue simulation
Yes
1) Display POOH advising for critical bit wear
2) Display Change para advising based on parameter optimization results
Parameter optimization (run calibrated model up to this point parallel on another server)
Compare simulation with real time data
Matched?
Yes
No

FIG. 10

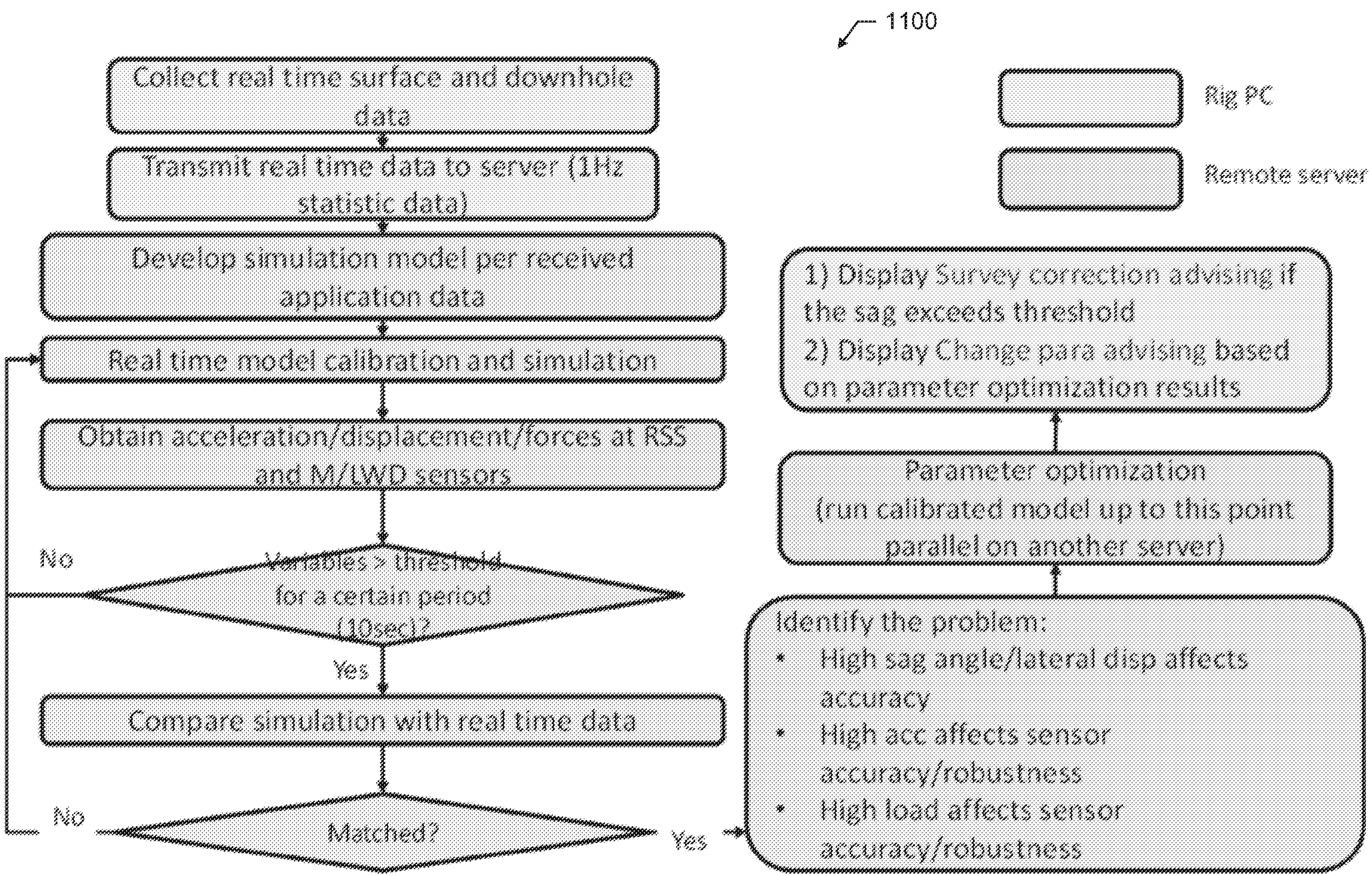
1100
Rig PC
Remote server
Collect real time surface and downhole data
Transmit real time data to server (1Hz statistic data)
Develop simulation model per received application data
Real time model calibration and simulation
Obtain acceleration/displacement/forces at RSS and M/LWD sensors
Variables > threshold for a certain period (10sec)?
No
Yes
Compare simulation with real time data
Matched?
No
Yes
Identify the problem:
* High sag angle/lateral disp affects accuracy
* High acc affects sensor accuracy/robustness
* High load affects sensor accuracy/robustness
Parameter optimization
(run calibrated model up to this point parallel on another server)
1) Display Survey correction advising if the sag exceeds threshold
2) Display Change para advising based on parameter optimization results

FIG. 11

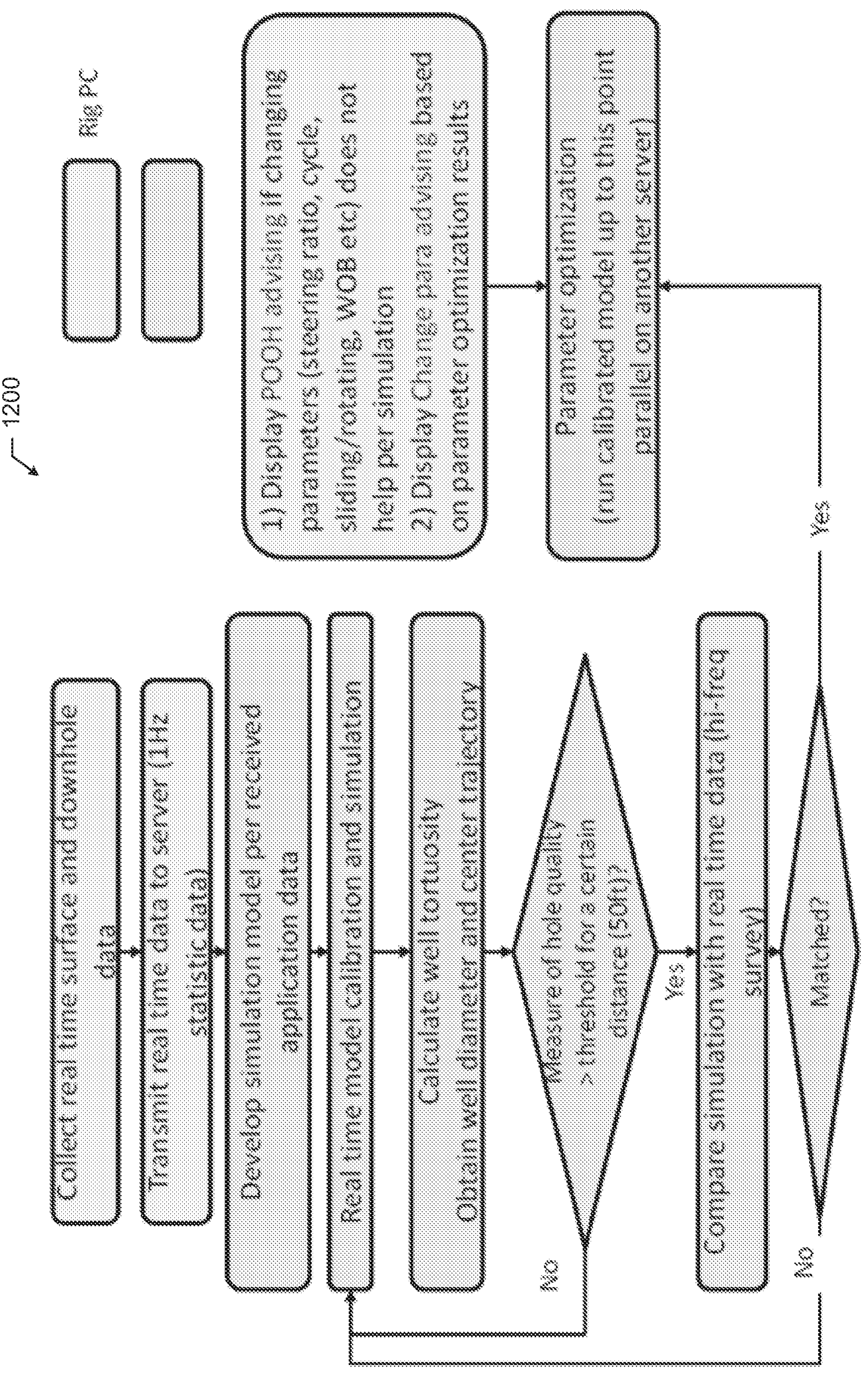
1200
Rig PC
Collect real time surface and downhole data
Transmit real time data to server (1Hz statistic data)
Develop simulation model per received application data
Real time model calibration and simulation
Calculate well tortuosity
Obtain well diameter and center trajectory
Measure of hole quality > threshold for a certain distance (50ft)?
No
Yes
Compare simulation with real time data (hi-freq survey)
Matched?
No
Yes
1) Display POOH advising if changing parameters (steering ratio, cycle, sliding/rotating, WOB etc) does not help per simulation
2) Display Change para advising based on parameter optimization results
Parameter optimization
(run calibrated model up to this point parallel on another server)

FIG. 12

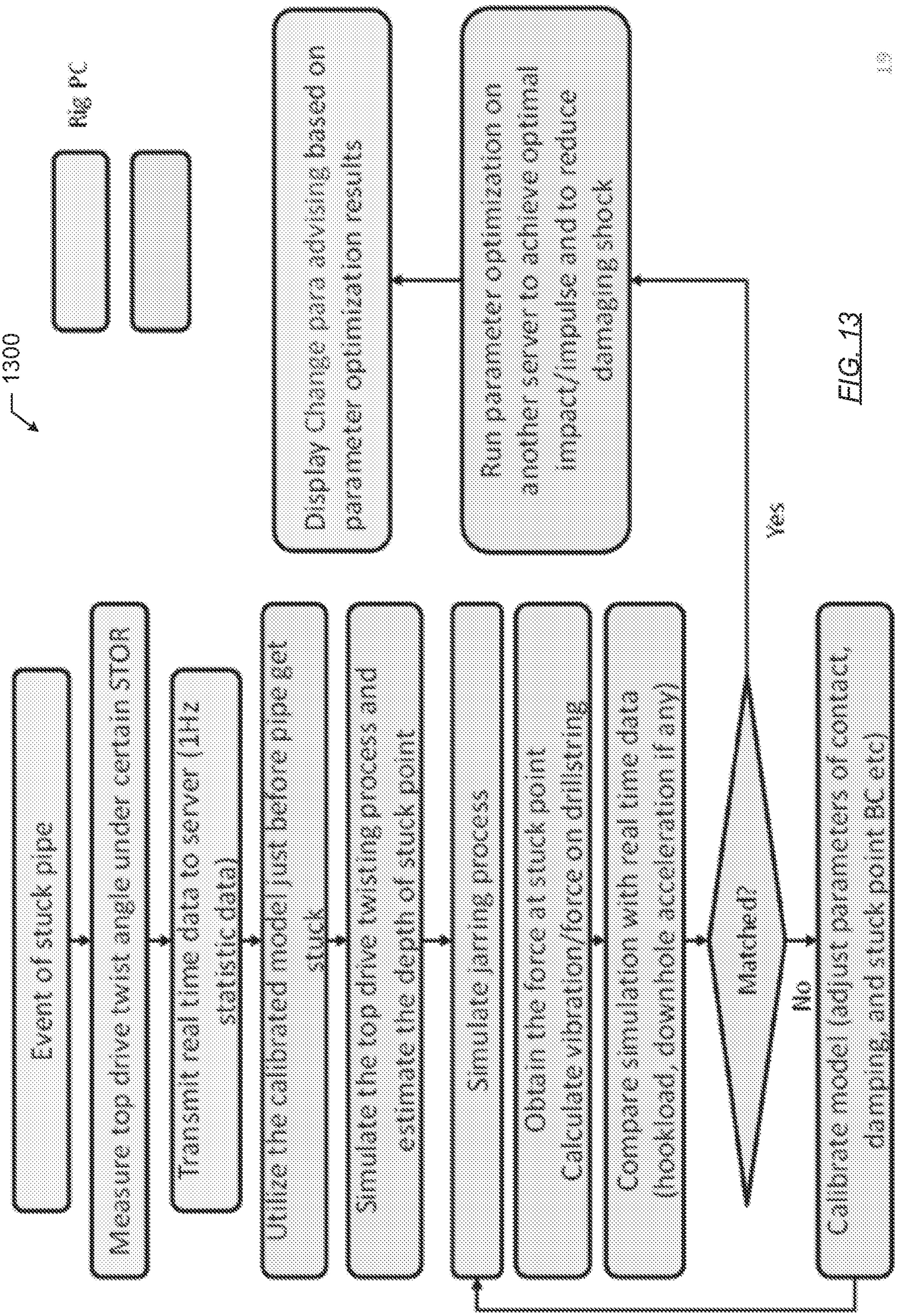
1300
Rig PC
Event of stuck pipe
Measure top drive twist angle under certain STOR
Transmit real time data to server (1Hz statistic data)
Utilize the calibrated model just before pipe get stuck
Simulate the top drive twisting process and estimate the depth of stuck point
Simulate jarring process
Obtain the force at stuck point
Calculate vibration/force on drillstring
Compare simulation with real time data (hookload, downhole acceleration if any)
Matched?
Yes
No
Calibrate model (adjust parameters of contact, damping, and stuck point BC etc)
Run parameter optimization on another server to achieve optimal impact/impulse and to reduce damaging shock
Display Change para advising based on parameter optimization results

FIG. 13

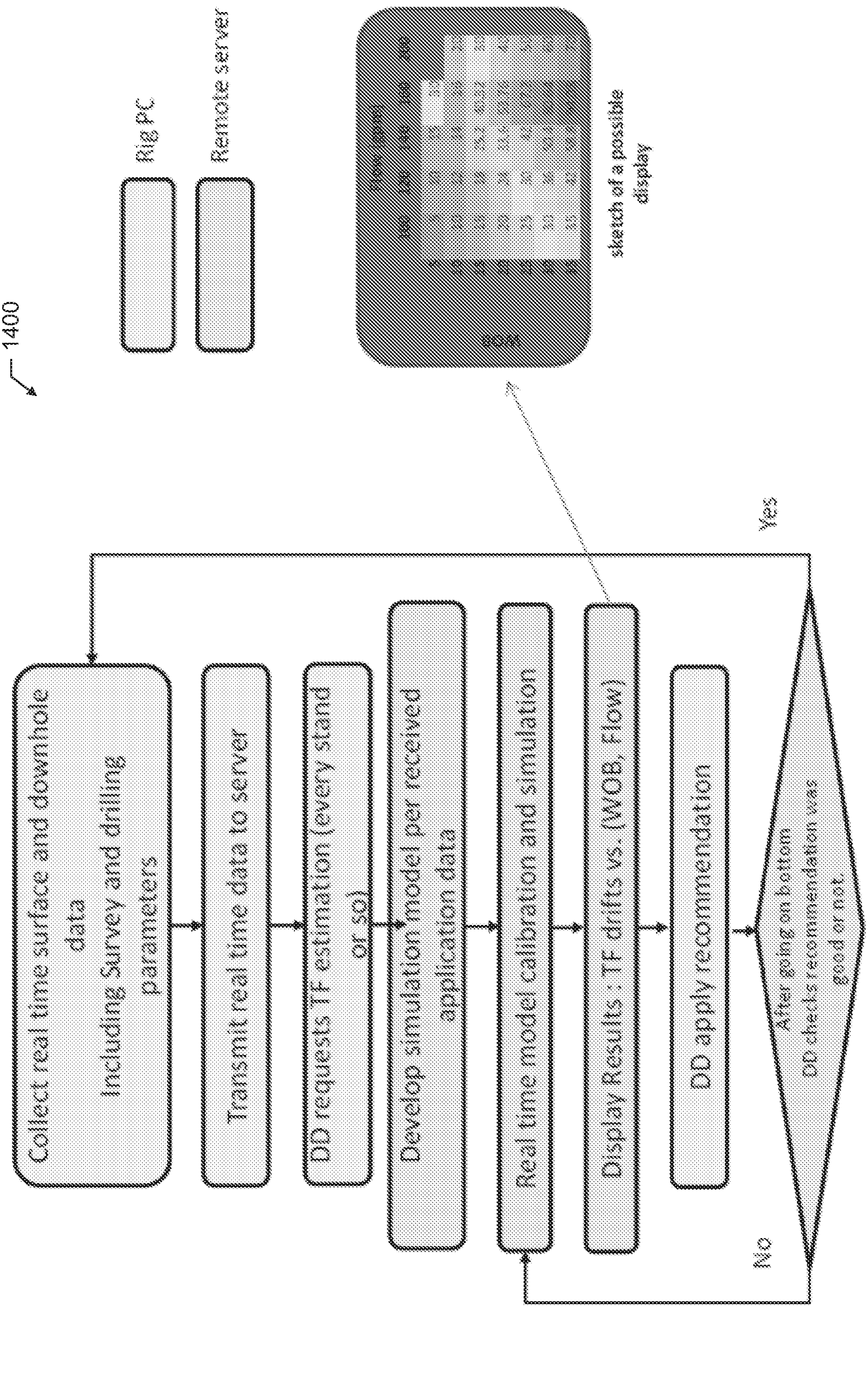
1400
Rig PC
Remote server
Collect real time surface and downhole data
Including Survey and drilling parameters
Transmit real time data to server
DD requests TF estimation (every stand or so)
Develop simulation model per received application data
Real time model calibration and simulation
Display Results : TF drifts vs. (WOB, Flow)
DD apply recommendation
After going on bottom DD checks recommendation was good or not
Yes
No
sketch of a possible display

FIG.14

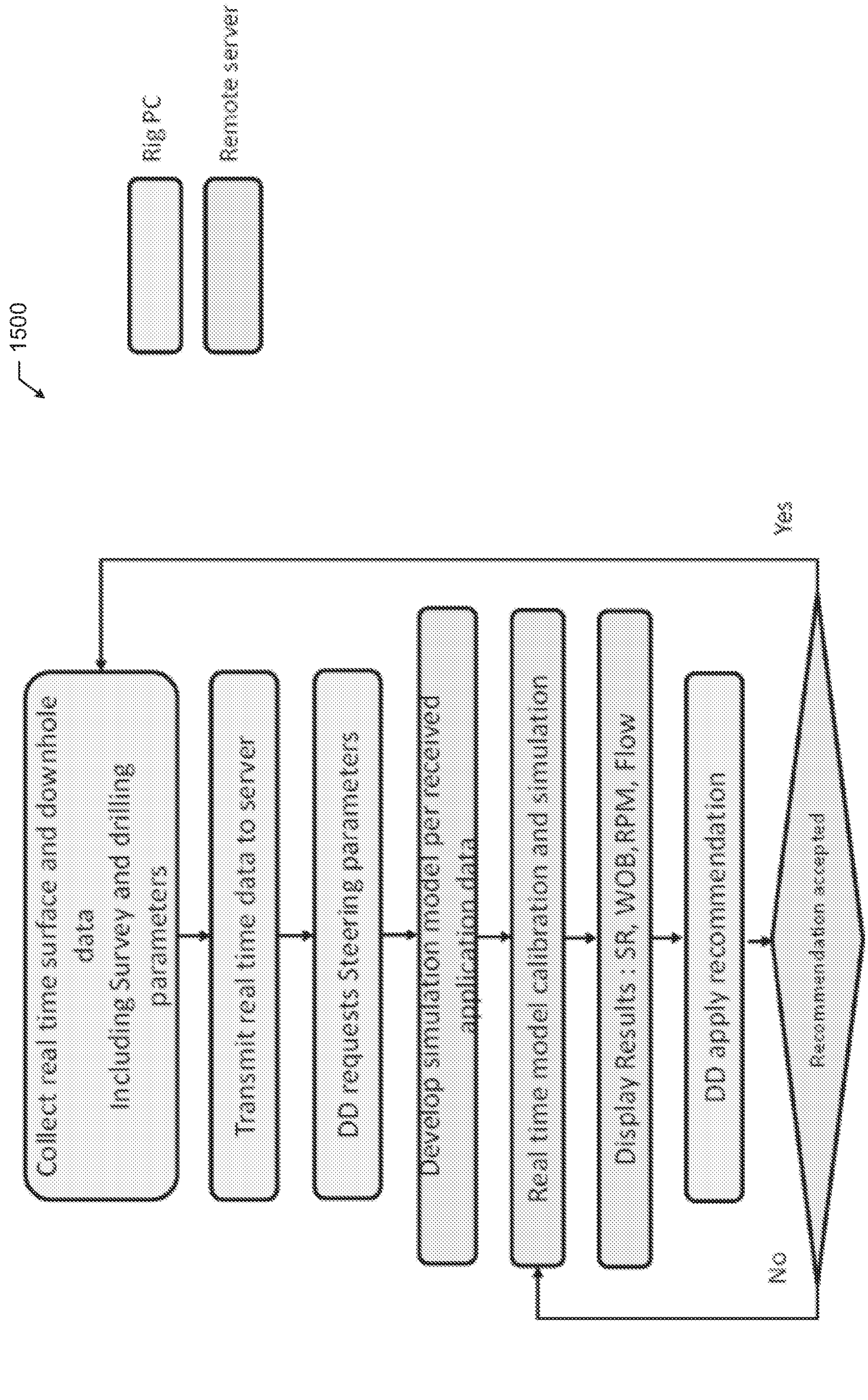
1500
Rig PC
Remote server
Collect real time surface and downhole data
Including Survey and drilling parameters
Transmit real time data to server
DD requests Steering parameters
Develop simulation model per received application data
Real time model calibration and simulation
Display Results : SR, WOB, RPM, Flow
DD apply recommendation
Recommendation accepted
Yes
No

FIG. 15

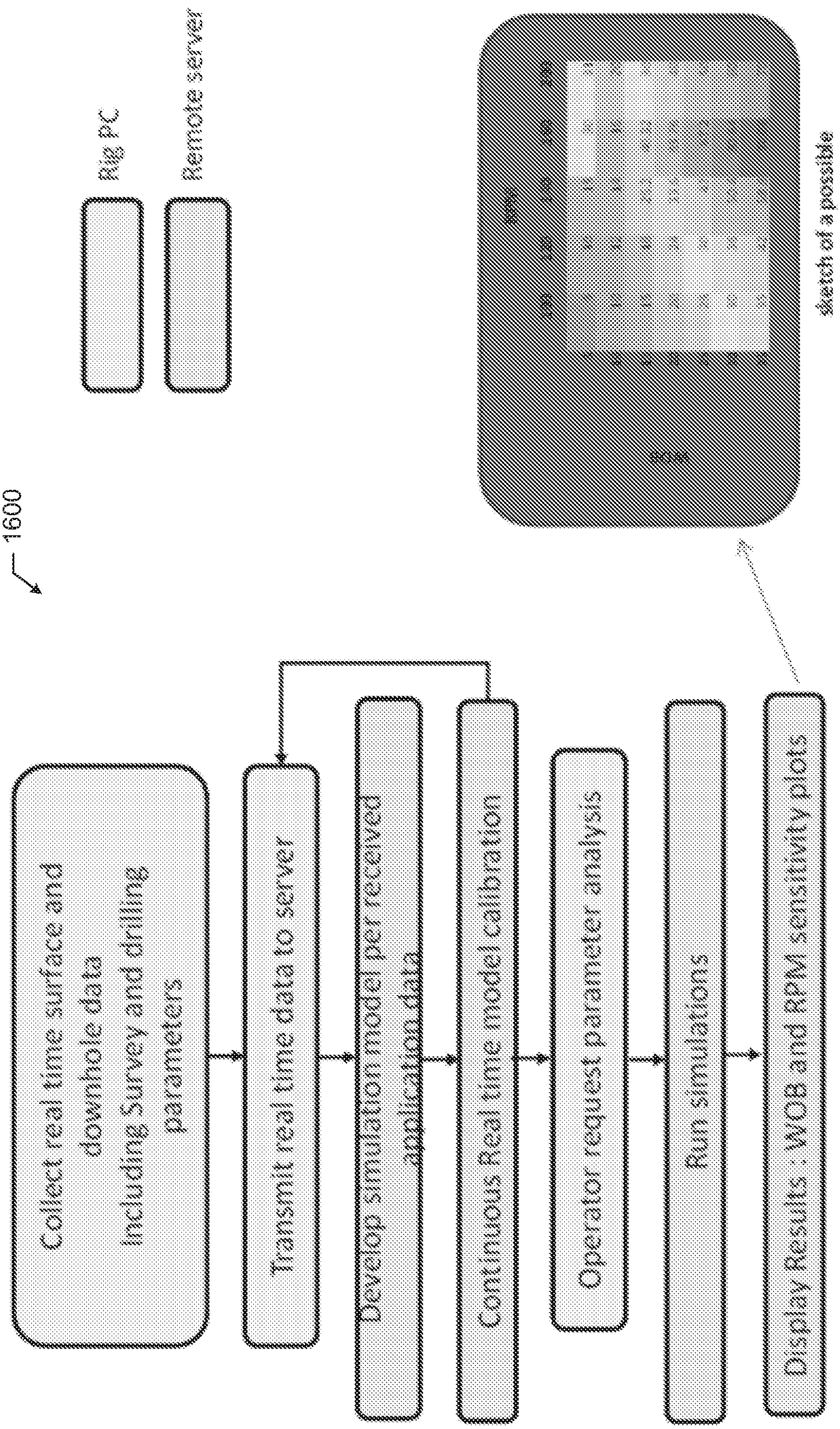
1600
Rig PC
Remote server
Collect real time surface and downhole data Including Survey and drilling parameters
Transmit real time data to server
Develop simulation model per received application data
Continuous Real time model calibration
Operator request parameter analysis
Run simulations
Display Results : WOB and RPM sensitivity plots
sketch of a possible display

FIG. 16

INTERNATIONAL SEARCH REPORT

International application No.
PCT/CN2015/078613

A. CLASSIFICATION OF SUBJECT MATTER

E21B 44/00(2006.01)i

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

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

E21B

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, WPI, EPODOC, CNKI, GOOGLE, IEEE:drill+, model?, calibrat+, updat+, refin+, measur+, actual, predict+, expect+, estimat+, simulat+, compar+, match+, threshold+, parameter+， propert+

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2015083492 A1 (WASSELL, MARK ELLSWORTH) 26 March 2015 (2015-03-26) description, paragraphs [0031] to [0033], [0102] to [0111], figures 2A, 2B and 6	1-22
A	US 2014262246 A1 (LI, ZHILIN ET AL.) 18 September 2014 (2014-09-18) the whole document	1-22
A	US 2004154831 A1 (SEYDOUX, JEAN ET AL.) 12 August 2004 (2004-08-12) the whole document	1-22
A	CN 203134246 U (LI, XUEJUN) 14 August 2013 (2013-08-14) the whole document	1-22

☐ 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
02 December 2015	**02 February 2016**

Name and mailing address of the ISA/CN	Authorized officer
STATE INTELLECTUAL PROPERTY OFFICE OF THE P.R.CHINA **6, Xitucheng Rd., Jimen Bridge, Haidian District, Beijing 100088, China**	**YANG,Jishuang**
Facsimile No. **(86-10)62019451**	Telephone No. **(86-10)62414422**

INTERNATIONAL SEARCH REPORT
Information on patent family members

International application No.
PCT/CN2015/078613

Patent document cited in search report	Publication date (day/month/year)	Patent family member(s)	Publication date (day/month/year)
US 2015083492 A1	26 March 2015	CA 2864545 A1	25 March 2015
		CN 104453848 A	25 March 2015
US 2014262246 A1	18 September 2014	WO 2013059971 A1	02 May 2013
		CN 102402184 A	04 April 2012
US 2004154831 A1	12 August 2004	NO 20040590 A	12 August 2004
		GB 2399180 A	08 September 2004
		FR 2854424 A1	05 November 2004
CN 203134246 U	14 August 2013	None	