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(54) Title: MULTI-STAGE ITERATIVE SOURCE SEPARATION WITH PRIOR FOR TIME-LAPSE ACQUISITION

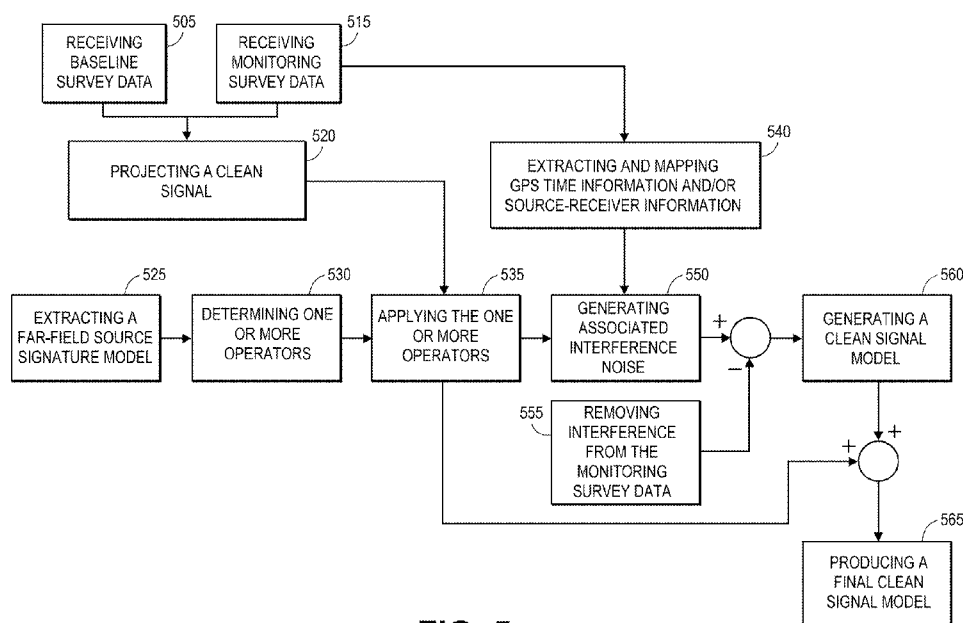


FIG. 5

(57) **Abstract:** A multi-stage source separation method for processing time-lapse seismic survey data for marine and/or land environments includes receiving baseline survey data. The method also includes receiving monitoring survey data. The monitoring survey data is acquired after the baseline survey data. The method also includes modifying the baseline survey data to produce processed baseline survey data. The method also includes generating associated interference noise based upon the processed baseline survey data. The method also includes removing interference from the monitoring survey data based upon the associated interference noise to produce residual model data. The method also includes generating a clean signal model based upon the residual model data. The method also includes combining the processed baseline survey data and the clean signal model to produce a final clean signal model.

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MULTI-STAGE ITERATIVE SOURCE SEPARATION WITH PRIOR FOR TIME-LAPSE ACQUISITION

Cross-Reference to Related Applications

[0001] This application claims priority to U.S. Provisional Patent Application No. 63/477,508, filed on December 28, 2022, which is incorporated herein by reference.

Background

[0002] Time-lapse seismic data acquisition is used for monitoring changes in a reservoir's fluid flows, and more recently, for carbon sequestration. Maintaining data repeatability in time-lapse seismic data acquisition results using ocean-bottom node (OBN) or ocean-bottom cable (OBC) design generally may produce densely sampled large-scale 3D OBN/OBC acquisitions. Such acquisitions are expensive. Moreover, repeating OBN acquisition many times to acquire time-lapse data further increases the acquisition costs.

[0003] To alleviate the cost of the seismic survey(s), simultaneous source acquisition designs are sometimes used, which reduces the acquisition time while potentially increasing the spatial sampling density. However, source interference generated during the simultaneous acquisition involves a robust source-separation optimization framework to remove the interference noise, known as deblending. Various sparsity or low-rank inversion-based technologies show improved source-separation results where the objective is to retain the coherent signal in the sparsity-promoting or rank-revealing transform domains while removing the interference.

[0004] Source separation generally relies on the degree of randomization in the acquisition design. Higher randomization results in a better signal-to-blending noise ratio (SNR) in the transform domain, whereas interference noise becomes smeared and uniformly distributed. Thus, identifying the right coherent signal becomes relatively easy as compared to the uniformly distributed interference noise in the transform domain. However, high randomization generally calls for the data to be acquired using the principle of compressive sensing (CS). CS-based acquisition design may not be practical due to environmental constraints, and as a result, data is acquired with a lower degree of randomization. Thus, many source-separation methods perform poorly because less randomization yields weaker signals that are less perceivable in the transform domain. That is, interference noise appears somewhat coherent and focused in the transform domain.

Summary

[0005] A multi-stage source separation method for processing time-lapse seismic survey data for marine and/or land environments is disclosed. The method includes receiving baseline survey data. The method also includes receiving monitoring survey data. The monitoring survey data is acquired after the baseline survey data. The method also includes modifying the baseline survey data to produce processed baseline survey data. The method also includes generating associated interference noise based upon the processed baseline survey data. The method also includes removing interference from the monitoring survey data based upon the associated interference noise to produce residual model data. The method also includes generating a clean signal model based upon the residual model data. The method also includes combining the processed baseline survey data and the clean signal model to produce a final clean signal model.

[0006] A computing system is also disclosed. The computing system includes one or more processors and a memory system. The memory system includes one or more non-transitory computer-readable media storing instructions that, when executed by at least one of the one or more processors, cause the computing system to perform operations. The operations include receiving baseline survey data. The operations also include generating a clean signal based upon the baseline survey data. The clean signal is generated using seismic processing. The operations also include receiving monitoring survey data. The monitoring survey data is acquired after the baseline survey data. The operations also include projecting the clean signal to locations of the monitoring survey data to produce an estimate of the clean signal at the locations of the monitoring survey data. The operations also include determining one or more operators based upon the baseline survey data, the monitoring survey data, or both. The one or more operators include a de-bubble operator and a global source matching operator. The operations also include modifying the baseline survey data to produce processed baseline survey data. The baseline survey data is modified using time-lapse processing. The baseline survey data is modified by applying the one or more operators to the estimate of the clean signal. The baseline survey data does not match the monitoring survey data. The processed baseline survey data matches the monitoring survey data. The operations also include generating associated interference noise based upon the processed baseline survey data. The associated interference noise is also generated based upon a blending operator. The blending operator models interference from simultaneous sources that generate the

monitoring survey data. The operations also include removing the interference from the monitoring survey data based upon the associated interference noise to produce residual model data. The operations also include generating a clean signal model based upon the residual model data. The clean signal model is generated using a noise attenuation framework. The noise attenuation framework includes a source separation technology. The operations also include combining the processed baseline survey data and the clean signal model to produce a final clean signal model for the monitoring survey data. The operations also include displaying the final clean signal model.

[0007] A non-transitory computer-readable medium is also disclosed. The medium stores instructions that, when executed by one or more processors of a computing system, cause the computing system to perform operations. The operations include receiving baseline survey data. The operations also include generating a clean signal based upon the baseline survey data. The clean signal is generated using seismic processing. The clean signal is generated in response to the baseline survey data being acquired using simultaneous shooting. The operations also include receiving monitoring survey data. The monitoring survey data is acquired after the baseline survey data. The operations also include projecting the clean signal to locations of the monitoring survey data to produce an estimate of the clean signal at the locations of the monitoring survey data. The clean signal is projected using an acquisition configuration of the monitoring survey data. The clean signal is projected using interpolation or regularization. The operations also include extracting a far-field source signature model from the monitoring survey data. The operations also include determining one or more operators based upon the baseline survey data, the monitoring survey data, or both. The one or more operators are based upon the baseline survey data and the far-field signature model. The one or more operators include a de-bubble operator and a global source matching operator. The operations also include modifying the baseline survey data to produce processed baseline survey data. The baseline survey data is modified using time-lapse processing. The baseline survey data is modified by applying the one or more operators to the estimate of the clean signal. The baseline survey data does not match the monitoring survey data. The processed baseline survey data matches the monitoring survey data. The operations also include extracting global positioning system (GPS) time information and source-receiver information from the monitoring survey data. The operations also include mapping the GPS time information and the source-receiver information to the baseline survey data to produce mapped

baseline survey data. The operations also include generating associated interference noise based upon the processed baseline survey data, the mapped baseline survey data, and a blending operator. The blending operator models interference from simultaneous sources that generate the monitoring survey data. The operations also include removing the interference from the monitoring survey data based upon the associated interference noise to produce residual model data. The interference is removed by adding the associated interference noise to the processed baseline survey data to produce estimated monitoring survey data. The interference is also removed by subtracting the estimated monitoring survey data from the monitoring survey data to produce the residual model data. The residual model data includes a residual signal and the associated interference noise of the monitoring survey data that is not explained by the baseline survey data. The operations also include generating a clean signal model based upon the residual model data. The clean signal model is generated using a noise attenuation framework. The noise attenuation framework includes a source separation technology. The operations also include combining the processed baseline survey data and the clean signal model to produce a final clean signal model for the monitoring survey data. The operations also include displaying the final clean signal model.

Brief Description of the Drawings

[0008] The accompanying drawings, which are incorporated in and constitute a part of this specification, illustrate embodiments of the present teachings and together with the description, serve to explain the principles of the present teachings. In the figures:

[0009] Figures 1A, 1B, 1C, 1D, 2, 3A, and 3B illustrate simplified, schematic views of an oilfield and its operation, according to an embodiment.

[0010] Figure 4 illustrates a flowchart of a method for multi-stage source separation in time-lapse surveys, according to an embodiment.

[0011] Figure 5 illustrates an illustrative order of the method in Figure 4, according to an embodiment.

[0012] Figure 6 illustrates a schematic view of a computing system for performing at least a portion of the method(s) described herein, according to an embodiment.

Description of Embodiments

[0013] Reference will now be made in detail to embodiments, examples of which are illustrated in the accompanying drawings and figures. In the following detailed description, numerous specific details are set forth in order to provide a thorough understanding of embodiments of the invention. However, it will be apparent to one of ordinary skill in the art that embodiments of the invention may be practiced without these specific details. In other instances, well-known methods, procedures, components, circuits and networks have not been described in detail so as not to unnecessarily obscure aspects of the embodiments.

[0014] It will also be understood that, although the terms first, second, etc. may be used herein to describe various elements, these elements should not be limited by these terms. These terms are only used to distinguish one element from another. For example, a first object could be termed a second object, and, similarly, a second object could be termed a first object, without departing from the scope of embodiments of the invention. The first object and the second object are both objects, respectively, but they are not to be considered the same object.

[0015] The terminology used in the description herein is for the purpose of describing particular embodiments only and is not intended to be limiting of the invention. As used in the description and the appended claims, the singular forms “a,” “an” and “the” are intended to include the plural forms as well, unless the context clearly indicates otherwise. It will also be understood that the term “and/or” as used herein refers to and encompasses any possible combinations of one or more of the associated listed items. It will be further understood that the terms “includes,” “including,” “comprises” and/or “comprising,” when used in this specification, specify the presence of stated features, integers, steps, operations, elements, and/or components, but do not preclude the presence or addition of one or more other features, integers, steps, operations, elements, components, and/or groups thereof. Further, as used herein, the term “if” may be construed to mean “when” or “upon” or “in response to determining” or “in response to detecting,” depending on the context.

[0016] Attention is now directed to processing procedures, methods, techniques and workflows that are in accordance with some embodiments. Some operations in the processing procedures, methods, techniques and workflows disclosed herein may be combined and/or the order of some operations may be changed.

[0017] Figures 1A-1D illustrate simplified, schematic views of oilfield 100 having subterranean formation 102 containing reservoir 104 therein in accordance with implementations of various technologies and techniques described herein. Figure 1A illustrates a survey operation being performed by a survey tool, such as seismic truck 106a, to measure properties of the subterranean formation. The survey operation is a seismic survey operation for producing sound vibrations. In Figure 1A, one such sound vibration, e.g., sound vibration 112 generated by source 110, reflects off horizons 114 in earth formation 116. A set of sound vibrations is received by sensors, such as geophone-receivers 118, situated on the earth's surface. The data received 120 is provided as input data to a computer 122a of a seismic truck 106a, and responsive to the input data, computer 122a generates seismic data output 124. This seismic data output may be stored, transmitted or further processed as desired, for example, by data reduction.

[0018] Figure 1B illustrates a drilling operation being performed by drilling tools 106b suspended by rig 128 and advanced into subterranean formations 102 to form wellbore 136. Mud pit 130 is used to draw drilling mud into the drilling tools via flow line 132 for circulating drilling mud down through the drilling tools, then up wellbore 136 and back to the surface. The drilling mud is typically filtered and returned to the mud pit. A circulating system may be used for storing, controlling, or filtering the flowing drilling mud. The drilling tools are advanced into subterranean formations 102 to reach reservoir 104. Each well may target one or more reservoirs. The drilling tools are adapted for measuring downhole properties using logging while drilling tools. The logging while drilling tools may also be adapted for taking core sample 133 as shown.

[0019] Computer facilities may be positioned at various locations about the oilfield 100 (e.g., the surface unit 134) and/or at remote locations. Surface unit 134 may be used to communicate with the drilling tools and/or offsite operations, as well as with other surface or downhole sensors. Surface unit 134 is capable of communicating with the drilling tools to send commands to the drilling tools, and to receive data therefrom. Surface unit 134 may also collect data generated during the drilling operation and produce data output 135, which may then be stored or transmitted.

[0020] Sensors (S), such as gauges, may be positioned about oilfield 100 to collect data relating to various oilfield operations as described previously. As shown, sensor (S) is positioned in one or more locations in the drilling tools and/or at rig 128 to measure drilling parameters, such as weight on bit, torque on bit, pressures, temperatures, flow rates, compositions, rotary speed, and/or

other parameters of the field operation. Sensors (S) may also be positioned in one or more locations in the circulating system.

[0021] Drilling tools 106b may include a bottom hole assembly (BHA) (not shown), generally referenced, near the drill bit (e.g., within several drill collar lengths from the drill bit). The bottom hole assembly includes capabilities for measuring, processing, and storing information, as well as communicating with surface unit 134. The bottom hole assembly further includes drill collars for performing various other measurement functions.

[0022] The bottom hole assembly may include a communication subassembly that communicates with surface unit 134. The communication subassembly is adapted to send signals to and receive signals from the surface using a communications channel such as mud pulse telemetry, electro-magnetic telemetry, or wired drill pipe communications. 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. It will be appreciated by one of skill in the art that a variety of telemetry systems may be employed, such as wired drill pipe, electromagnetic or other known telemetry systems.

[0023] Typically, the wellbore is drilled according to a drilling plan that is established prior to drilling. The drilling plan typically sets forth equipment, pressures, trajectories and/or other parameters that define the drilling process for the wellsite. The drilling operation may then be performed according to the drilling plan. However, as information is gathered, the drilling operation may need to deviate from the drilling plan. Additionally, as drilling or other operations are performed, the subsurface conditions may change. The earth model may also need adjustment as new information is collected.

[0024] The data gathered by sensors (S) may be collected by surface unit 134 and/or other data collection sources for analysis or other processing. The data collected by sensors (S) may be used alone or in combination with other data. The data may be collected in one or more databases and/or transmitted on or offsite. The data may be historical data, real time data, or combinations thereof. The real time data may be used in real time, or stored for later use. The data may also be combined with historical data or other inputs for further analysis. The data may be stored in separate databases, or combined into a single database.

[0025] Surface unit 134 may include transceiver 137 to allow communications between surface unit 134 and various portions of the oilfield 100 or other locations. Surface unit 134 may also be

provided with or functionally connected to one or more controllers (not shown) for actuating mechanisms at oilfield 100. Surface unit 134 may then send command signals to oilfield 100 in response to data received. Surface unit 134 may receive commands via transceiver 137 or may itself execute commands to the controller. A processor may be provided to analyze the data (locally or remotely), make the decisions and/or actuate the controller. In this manner, oilfield 100 may be selectively adjusted based on the data collected. This technique may be used to optimize (or improve) portions of the field operation, such as controlling drilling, weight on bit, pump rates, or other parameters. These adjustments may be made automatically based on computer protocol, and/or manually by an operator. In some cases, well plans may be adjusted to select optimum (or improved) operating conditions, or to avoid problems.

[0026] Figure 1C illustrates a wireline operation being performed by wireline tool 106c suspended by rig 128 and into wellbore 136 of Figure 1B. Wireline tool 106c is adapted for deployment into wellbore 136 for generating well logs, performing downhole tests and/or collecting samples. Wireline tool 106c may be used to provide another method and apparatus for performing a seismic survey operation. Wireline tool 106c may, for example, have an explosive, radioactive, electrical, or acoustic energy source 144 that sends and/or receives electrical signals to surrounding subterranean formations 102 and fluids therein.

[0027] Wireline tool 106c may be operatively connected to, for example, geophones 118 and a computer 122a of a seismic truck 106a of Figure 1A. Wireline tool 106c may also provide data to surface unit 134. Surface unit 134 may collect data generated during the wireline operation and may produce data output 135 that may be stored or transmitted. Wireline tool 106c may be positioned at various depths in the wellbore 136 to provide a survey or other information relating to the subterranean formation 102.

[0028] Sensors (S), such as gauges, may be positioned about oilfield 100 to collect data relating to various field operations as described previously. As shown, sensor S is positioned in wireline tool 106c to measure downhole parameters which relate to, for example porosity, permeability, fluid composition and/or other parameters of the field operation.

[0029] Figure 1D illustrates a production operation being performed by production tool 106d deployed from a production unit or Christmas tree 129 and into completed wellbore 136 for drawing fluid from the downhole reservoirs into surface facilities 142. The fluid flows from

reservoir 104 through perforations in the casing (not shown) and into production tool 106d in wellbore 136 and to surface facilities 142 via gathering network 146.

[0030] Sensors (S), such as gauges, may be positioned about oilfield 100 to collect data relating to various field operations as described previously. As shown, the sensor (S) may be positioned in production tool 106d or associated equipment, such as Christmas tree 129, gathering network 146, surface facility 142, and/or the production facility, to measure fluid parameters, such as fluid composition, flow rates, pressures, temperatures, and/or other parameters of the production operation.

[0031] Production may also include injection wells for added recovery. One or more gathering facilities may be operatively connected to one or more of the wellsites for selectively collecting downhole fluids from the wellsite(s).

[0032] While Figures 1B-1D illustrate tools used to measure properties of an oilfield, it will be appreciated that the tools may be used in connection with non-oilfield operations, such as gas fields, mines, aquifers, storage or other subterranean facilities. Also, while certain data acquisition tools are depicted, it will be appreciated that various measurement tools capable of sensing parameters, such as seismic two-way travel time, density, resistivity, production rate, etc., of the subterranean formation and/or its geological formations may be used. Various sensors (S) may be located at various positions along the wellbore and/or the monitoring tools to collect and/or monitor the desired data. Other sources of data may also be provided from offsite locations.

[0033] The field configurations of Figures 1A-1D are intended to provide a brief description of an example of a field usable with oilfield application frameworks. Part of, or the entirety, of oilfield 100 may be on land, water and/or sea. Also, while a single field measured at a single location is depicted, oilfield applications may be utilized with any combination of one or more oilfields, one or more processing facilities and one or more wellsites.

[0034] Figure 2 illustrates a schematic view, partially in cross section of oilfield 200 having data acquisition tools 202a, 202b, 202c and 202d positioned at various locations along oilfield 200 for collecting data of subterranean formation 204 in accordance with implementations of various technologies and techniques described herein. Data acquisition tools 202a-202d may be the same as data acquisition tools 106a-106d of Figures 1A-1D, respectively, or others not depicted. As shown, data acquisition tools 202a-202d generate data plots or measurements 208a-208d,

respectively. These data plots are depicted along oilfield 200 to demonstrate the data generated by the various operations.

[0035] Data plots 208a-208c are examples of static data plots that may be generated by data acquisition tools 202a-202c, respectively; however, it should be understood that data plots 208a-208c may also be data plots that are updated in real time. These measurements may be analyzed to better define the properties of the formation(s) and/or determine the accuracy of the measurements and/or for checking for errors. The plots of each of the respective measurements may be aligned and scaled for comparison and verification of the properties.

[0036] Static data plot 208a is a seismic two-way response over a period of time. Static plot 208b is core sample data measured from a core sample of the formation 204. The core sample may be used to provide data, such as a graph of the density, porosity, permeability, or some other physical property of the core sample over the length of the core. Tests for density and viscosity may be performed on the fluids in the core at varying pressures and temperatures. Static data plot 208c is a logging trace that typically provides a resistivity or other measurement of the formation at various depths.

[0037] A production decline curve or graph 208d is a dynamic data plot of the fluid flow rate over time. The production decline curve typically provides the production rate as a function of time. As the fluid flows through the wellbore, measurements are taken of fluid properties, such as flow rates, pressures, composition, etc.

[0038] Other data may also be collected, such as historical data, user inputs, economic information, and/or other measurement data and other parameters of interest. As described below, the static and dynamic measurements may be analyzed and used to generate models of the subterranean formation to determine characteristics thereof. Similar measurements may also be used to measure changes in formation aspects over time.

[0039] The subterranean structure 204 has a plurality of geological formations 206a-206d. As shown, this structure has several formations or layers, including a shale layer 206a, a carbonate layer 206b, a shale layer 206c and a sand layer 206d. A fault 207 extends through the shale layer 206a and the carbonate layer 206b. The static data acquisition tools are adapted to take measurements and detect characteristics of the formations.

[0040] While a specific subterranean formation with specific geological structures is depicted, it will be appreciated that oilfield 200 may contain a variety of geological structures and/or

formations, sometimes having extreme complexity. In some locations, typically below the water line, fluid may occupy pore spaces of the formations. Each of the measurement devices may be used to measure properties of the formations and/or its geological features. While each acquisition tool is shown as being in specific locations in oilfield 200, it will be appreciated that one or more types of measurement may be taken at one or more locations across one or more fields or other locations for comparison and/or analysis.

[0041] The data collected from various sources, such as the data acquisition tools of Figure 2, may then be processed and/or evaluated. Typically, seismic data displayed in static data plot 208a from data acquisition tool 202a is used by a geophysicist to determine characteristics of the subterranean formations and features. The core data shown in static plot 208b and/or log data from well log 208c are typically used by a geologist to determine various characteristics of the subterranean formation. The production data from graph 208d is typically used by the reservoir engineer to determine fluid flow reservoir characteristics. The data analyzed by the geologist, geophysicist and the reservoir engineer may be analyzed using modeling techniques.

[0042] Figure 3A illustrates an oilfield 300 for performing production operations in accordance with implementations of various technologies and techniques described herein. As shown, the oilfield has a plurality of wellsites 302 operatively connected to central processing facility 354. The oilfield configuration of Figure 3A is not intended to limit the scope of the oilfield application system. 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.

[0043] Each wellsite 302 has equipment that forms wellbore 336 into the Earth. The wellbores extend through subterranean formations 306 including reservoirs 304. These reservoirs 304 contain fluids, such as hydrocarbons. The wellsites draw fluid from the reservoirs and pass them to the processing facilities via surface networks 344. The surface networks 344 have tubing and control mechanisms for controlling the flow of fluids from the wellsite to processing facility 354.

[0044] Attention is now directed to Figure 3B, which illustrates a side view of a marine-based survey 360 of a subterranean subsurface 362 in accordance with one or more implementations of various techniques described herein. Subsurface 362 includes seafloor surface 364. Seismic sources 366 may include marine sources such as vibroseis or airguns, which may propagate seismic waves 368 (e.g., energy signals) into the Earth over an extended period of time or at a nearly

instantaneous energy provided by impulsive sources. The seismic waves may be propagated by marine sources as a frequency sweep signal. For example, marine sources of the vibroseis type may initially emit a seismic wave at a low frequency (e.g., 5 Hertz (Hz)) and increase the seismic wave to a high frequency (e.g., 80-90 Hz) over time.

[0045] The component(s) of the seismic waves 368 may be reflected and converted by seafloor surface 364 (i.e., reflector), and seismic wave reflections 370 may be received by a plurality of seismic receivers 372. Seismic receivers 372 may be disposed on a plurality of streamers (i.e., streamer array 374). The seismic receivers 372 may generate electrical signals representative of the received seismic wave reflections 370. The electrical signals may be embedded with information regarding the subsurface 362 and captured as a record of seismic data.

[0046] In one implementation, each streamer may include streamer steering devices such as a bird, a deflector, a tail buoy and the like, which are not illustrated in this application. The streamer steering devices may be used to control the position of the streamers in accordance with the techniques described herein.

[0047] In one implementation, seismic wave reflections 370 may travel upward and reach the water/air interface at the water surface 376, a portion of reflections 370 may then reflect downward again (i.e., sea-surface ghost waves 378) and be received by the plurality of seismic receivers 372. The sea-surface ghost waves 378 may be referred to as surface multiples. The point on the water surface 376 at which the wave is reflected downward is generally referred to as the downward reflection point.

[0048] The electrical signals may be transmitted to a vessel 380 via transmission cables, wireless communication or the like. The vessel 380 may then transmit the electrical signals to a data processing center. Alternatively, the vessel 380 may include an onboard computer capable of processing the electrical signals (i.e., seismic data). Those skilled in the art having the benefit of this disclosure will appreciate that this illustration is highly idealized. For instance, surveys may be of formations deep beneath the surface. The formations may typically include multiple reflectors, some of which may include dipping events, and may generate multiple reflections (including wave conversion) for receipt by the seismic receivers 372. In one implementation, the seismic data may be processed to generate a seismic image of the subsurface 362.

[0049] Marine seismic acquisition systems tow each streamer in streamer array 374 at the same depth (e.g., 5-10 meters (m)). However, marine based survey 360 may tow each streamer in

streamer array 374 at different depths such that seismic data may be acquired and processed in a manner that avoids the effects of destructive interference due to sea-surface ghost waves. For instance, marine-based survey 360 of Figure 3B illustrates eight streamers towed by vessel 380 at eight different depths. The depth of each streamer may be controlled and maintained using the birds disposed on each streamer.

[0050] Multi-Stage Iterative Source Separation with Prior for Time-Lapse Acquisition

[0051] An inversion-based, multi-stage, iterative source separation with priors (MS-ISSP) framework has been designed to progressively model the source-separated signal while eliminating the interference in a signal-safe manner. The method adopts a multi-stage strategy where different sparsity-promoting prior information is utilized to optimize the SNR at each stage. In each stage, the algorithm focuses on separating different modes of a seismic signal starting with the strongest signal. The combination of the multi-stage strategy and the sparsity-promoting priors provides enhanced source separation performance compared to conventional inversion methods. While MS-ISSP outperforms the source-separation techniques, when it comes to time-lapse acquisition, it does not exploit the benefit that different surveys are mapping the same earth over a time window. As a result, source-separation using MS-ISSP is performed independently across different vintages (i.e., baseline and monitor surveys acquired over a period).

[0052] Embodiments of the present disclosure may utilize the knowledge that different surveys are acquired over the same subsurface geology where changes are expected in and around the reservoir, but generally not elsewhere. Accordingly, a baseline signal (also referred to as baseline survey data) is used as a prior model to instantiate the MS-ISSP framework for monitoring surveys (also referred to as monitoring survey data). The data acquired by the monitor survey differs due to the time-lapse change. Thus, a majority of the monitor data should match the baseline survey data.

[0053] The baseline data may have already been processed (e.g., cleaned), and is either acquired using sequential survey or using simultaneous design, then that processed baseline data may be used to explain most of the energy present in the monitor surveys. If the baseline survey is acquired using the simultaneous design, then the interference noise may be removed using a source-separation technique to get a clean signal model.

[0054] It is noted that, for most of the conventional simultaneous acquisition designs, the major source of interference noise is direct arrival energy. Moreover, predicting and removing the correct

direct arrival energy is a challenge, especially when data is acquired in a design where randomization in the interference noise is minimal. By utilizing the baseline signal model as a prior, a bottleneck of the source separation, which is to separate direct arrival energy while preserving the weak energy buried beneath the interference noise coming from the direct arrival, can be mitigated.

[0055] Another assumption of using the baseline signal model as an initial guess for the monitor survey using the methodology, according to some examples, is that the acquisition configuration for the baseline and monitor survey may be similar and/or the same. In some scenarios, if the monitoring and baseline survey datasets are acquired with different sources volumes and depth, then it can lead to differences in the data, bubble and ghost. To mitigate this, far-field signatures generated from near-field hydrophone measurements are used to generate a debubble operator, which is applied to the prior dataset to attenuate the strong bubble energy. A bulk matching operator is also designed using the far-field signatures to match the prior dataset to the monitor survey to compensate for source variations between the vintages.

[0056] Figure 4 illustrates a flowchart of a method 400 for multi-stage source separation in time-lapse surveys, according to an embodiment. More particularly the method 400 may be for processing time-lapse seismic survey data for marine and/or land environments. As described below, the method 400 may use baseline survey data as a prior (e.g., initial guess) for monitoring survey data. Figure 5 illustrates an illustrative order of the method 400; however, one or more portions of the method 400 may be performed in a different order, simultaneously, repeated, or omitted.

[0057] The method 400 may include receiving baseline survey data (also referred to as a baseline signal model), as at 405. This is also shown at 505 in Figure 5. The baseline survey data may be or include seismic data such as particle measurements, velocity measurements, displacement measurements, acceleration measurements, optical fibre measurements, or a combination thereof. The baseline survey data may be acquired using sequential or simultaneous shooting. The baseline survey data may be acquired on a regular or irregular grid. The baseline survey data may be a starting guess for the monitoring survey data to de-blend a plurality of possible modes of a seismic event for the monitoring survey data for any acquisition design in the marine and/or land environment.

[0058] The method 400 may also include generating a first (e.g., clean) signal based upon the baseline survey data, as at 410. The first (e.g., clean) signal may be generated using seismic processing. The first (e.g., clean) signal may be generated in response to the baseline survey data being acquired using simultaneous shooting.

[0059] The method 400 may also include receiving monitoring survey data, as at 415. This is also shown at 515 in Figure 5. The monitoring survey data may be or include seismic data. The monitoring survey data may be acquired on a regular or irregular grid. The monitoring survey data may be acquired after the baseline survey data.

[0060] The method 400 may also include projecting the first (e.g., clean) signal to locations of the monitoring survey data to produce a second signal, as at 420. This is also shown at 520 in Figure 5. The second signal may be an estimate of the first (e.g., clean) signal at the locations of the monitoring survey data. The first (e.g., clean) signal may be projected using an acquisition configuration of the monitoring survey data. The first (e.g., clean) signal may be projected using interpolation or regularization. Matching Pursuit Fourier Interpolation (MPFI) or any other interpolation scheme can be used. The outcome of the interpolation may not be regular grid data, but the second signal (also referred to as a baseline signal model) mapped to the field locations of the monitoring survey data.

[0061] The method 400 may also include extracting a far-field source signature model from the monitoring survey data, as at 425. This is also shown at 525 in Figure 5.

[0062] The method 400 may also include determining one or more operators based upon the baseline survey data and/or the monitoring survey data, as at 430. This is also shown at 530 in Figure 5. More particularly, this may include determining a de-bubble operator and/or a global source matching operator based upon baseline survey data and/or the far-field signature model.

[0063] The method 400 may also include modifying the baseline survey data to produce processed baseline survey data, as at 435. This is also shown at 535 in Figure 5. More particularly, the one or more operators may be applied to the baseline survey data (e.g., the second signal) to cause the baseline survey data to match the monitoring survey data (e.g., using time-lapse processing). In other words, the baseline survey data does not match the monitoring survey data, and the processed baseline survey data matches the monitoring survey data.

[0064] The method 400 may also include extracting GPS time information and/or source-receiver information from the monitoring survey data, as at 440.

[0065] The method may also include mapping the GPS time information and/or source-receiver information to the baseline survey data to produce mapped baseline survey data, as at 445.

[0066] The method 400 may also include generating associated interference noise based upon the processed baseline survey data, as at 450. This is also shown at 550 in Figure 5. In one embodiment, the associated interference noise may be generated using the processed baseline survey data, the mapped baseline survey data, a blending operator, or a combination thereof. The blending operator models interference from simultaneous sources (e.g., the sources that are/were used to generate the monitoring survey data).

[0067] The method 400 may also include removing the interference from the monitoring survey data to produce residual model data, as at 455. This is also shown at 550 in Figure 5. The interference may be removed based upon the associated interference noise. More particularly, the interference may be removed by adding the associated interference noise to the processed baseline survey data to produce estimated monitoring survey data, as at 456. The interference may also or instead be removed by subtracting the estimated monitoring survey data from the monitoring survey data to produce the residual model data, as at 457. This may yield residual energy from the monitoring survey data (i.e., energy not explained by the baseline survey data), including a residual signal and/or the associated interference noise.

[0068] The method 400 may also include generating a clean signal model based upon the residual model data, as at 460. This is also shown at 560 in Figure 5. The clean signal model may be generated using a noise attenuation framework. The noise attenuation framework may be or include a source separation technology (e.g., MS-ISSP).

[0069] The method 400 may also include combining the processed baseline survey data and the clean signal model to produce a final clean signal model for the monitoring survey data, as at 465.

[0070] The method 400 may also include displaying the final clean signal model, as at 470.

[0071] The method 400 may also include performing a wellsite action, as at 475. The wellsite action may be performed in response to the final clean signal model. The wellsite action may be or include generating and/or transmitting a signal (e.g., using a computing system) that causes a physical action to occur at a wellsite. The wellsite action may also or instead include performing the physical action at the wellsite. The physical action may include selecting where to drill a wellbore, drilling the wellbore, varying a weight and/or torque on a drill bit that is drilling the

wellbore, varying a drilling trajectory of the wellbore, varying a concentration and/or flow rate of a fluid pumped into the wellbore, or the like.

[0072] One or more portions of the method 400 may be iterative, and at each iteration:

- a) A set of prior information may separate aliased events from non-aliased events in the baseline survey data and the monitoring survey data. The method 400 may also include selecting one or more coefficients for true events present in a transform domain.
- b) The set of prior information may include noise attenuation of the seismic data.
- c) The set of prior information may include different frequency bandwidths of the aliased and/or non-aliased events.
- d) The set of prior information may include localizing a strongest mode of energy by applying a pre-design mute.
- e) The set of prior information may include velocity model information of the seismic data.
- f) The prior information may include a moveout to different modes in the seismic data.
- g) The modes of the seismic data may include direct arrival, reflection, refraction, diffractions, and surface waves such as ground roll, Scholte waves, shear noise, and/or mud roll.
- h) The multi-stage source separation with baseline signal model as a starting guess can be performed by either using sparsity-based techniques or using rank-minimization-based techniques.

[0073] For time-lapse acquisitions, the baseline signal model may be incorporated as prior information when performing source separation on the monitor datasets. The proposed framework may allow handling strong interference noise overlays on top of weak signals for the monitor survey. Moreover, using the baseline signal model as a prior, the computational burden of performing source separation on the monitor survey may be reduced. More particularly, at the very first iteration, the baseline signal model and the associated interference noise may be removed from the monitor survey. Thus, the source separation may be performed on the monitor survey data, which is not common in the baseline surveys.

[0074] The time-lapse acquisition may be used when monitoring the changes in the reservoir or during a carbon sequestration process. As time-lapse changes can be very weak in nature,

preserving them after source separation is a challenging task. This is even challenging when acquisition design is sub-optimal and common information presented between different surveys is not utilized properly. The conventional practice is to perform source separation on different vintages separately and then match the data in the post-stack domain. This results in not utilizing the common information present between the different surveys while performing the source separation. This also results in either spending too many computing resources while performing the source separation or creating a risk of losing a weak signal buried beneath the strong interference noise.

[0075] This present disclosure addresses these challenges by utilizing the multi-stage iterative source separation with a prior framework where a clean baseline signal model may be used as an initial guess to explain a large portion of the monitor survey before performing source separation on the residual signal and interference noise coming from the monitor survey. As a result, the system and method described herein may reduce the computational costs due to deblending a small portion of monitor survey data while removing the impediment of strong interference noise covering the weak signal model in the monitor survey.

[0076] The proposed source separation approach using the baseline model as a prior can be used for any acquisition environment with any acquisition design including regular and irregular geometries where the seismic data is acquired over a period to monitor subsurface changes. The conventional multi-stage source separation approach does not use the baseline as a prior signal model when performing source separation for the monitor surveys. As a result, the conventional approach does not exploit the common information present between different surveys acquired over a period.

[0077] The present disclosure exploits the common information that exists between the baseline survey and monitor survey to produce optimal source-separation results for the time-lapse acquisition while reducing the computational burden when dealing with the full spectrum of data while performing the source-separation for monitor surveys. This is the first instance of performing the source separation for time-lapse acquisition where the baseline signal model is used as a starting model for the monitor surveys. The proposed solution may provide a cost-efficient source-separation solution both qualitatively and quantitatively in time-lapse acquisition environments for reservoir monitoring during oil and gas production or carbon sequestration.

[0078] In one or more embodiments, the functions described can be implemented in hardware, software, firmware, or any combination thereof. For a software implementation, the techniques described herein can be implemented with modules (e.g., procedures, functions, subprograms, programs, routines, subroutines, modules, software packages, classes, and so on) that perform the functions described herein. A module can be coupled to another module or a hardware circuit by passing and/or receiving information, data, arguments, parameters, or memory contents. Information, arguments, parameters, data, or the like can be passed, forwarded, or transmitted using any suitable means including memory sharing, message passing, token passing, network transmission, and the like. The software codes can be stored in memory units and executed by processors. The memory unit can be implemented within the processor or external to the processor, in which case it can be communicatively coupled to the processor via various means as is known in the art.

[0079] In some embodiments, any of the methods of the present disclosure may be executed using a system, such as a computing system. Figure 6 illustrates an example of such a computing system 600, in accordance with some embodiments. The computing system 600 may include a computer or computer system 601a, which may be an individual computer system 601a or an arrangement of distributed computer systems. The computer system 601a includes one or more analysis module(s) 602 configured to perform various tasks according to some embodiments, such as one or more methods disclosed herein. To perform these various tasks, the analysis module 602 executes independently, or in coordination with, one or more processors 604, which is (or are) connected to one or more storage media 606. The processor(s) 604 is (or are) also connected to a network interface 605 to allow the computer system 601a to communicate over a data network 609 with one or more additional computer systems and/or computing systems, such as 601b, 601c, and/or 601d (note that computer systems 601b, 601c and/or 601d may or may not share the same architecture as computer system 601a, and may be located in different physical locations, e.g., computer systems 601a and 601b may be located in a processing facility, while in communication with one or more computer systems such as 601c and/or 601d that are located in one or more data centers, and/or located in varying countries on different continents).

[0080] A processor can include a microprocessor, microcontroller, processor module or subsystem, programmable integrated circuit, programmable gate array, or another control or computing device.

[0081] The storage media 606 can be implemented as one or more computer-readable or machine-readable storage media. Note that while in the example embodiment of Figure 6 storage media 606 is depicted as within computer system 601a, in some embodiments, storage media 606 may be distributed within and/or across multiple internal and/or external enclosures of computing system 601a and/or additional computing systems. Storage media 606 may include one or more different forms of memory including semiconductor memory devices such as dynamic or static random access memories (DRAMs or SRAMs), erasable and programmable read-only memories (EPROMs), electrically erasable and programmable read-only memories (EEPROMs) and flash memories, magnetic disks such as fixed, floppy and removable disks, other magnetic media including tape, optical media such as compact disks (CDs) or digital video disks (DVDs), BLURAY® disks, or other types of optical storage, or other types of storage devices. Note that the instructions discussed above can be provided on one computer-readable or machine-readable storage medium, or alternatively, can be provided on multiple computer-readable or machine-readable storage media distributed in a large system having possibly plural nodes. Such computer-readable or machine-readable storage medium or media is (are) considered to be part of an article (or article of manufacture). An article or article of manufacture can refer to any manufactured single component or multiple components. The storage medium or media can be located either in the machine running the machine-readable instructions, or located at a remote site from which machine-readable instructions can be downloaded over a network for execution.

[0082] In some embodiments, computing system 600 contains one or more source separation module(s) 608. In the example of computing system 600, computer system 601a includes the source separation module 608. In some embodiments, a single source separation module may be used to perform some or all aspects of one or more embodiments of the methods. In alternate embodiments, a plurality of source separation modules may be used to perform some or all aspects of methods.

[0083] It should be appreciated that computing system 600 is only one example of a computing system, and that computing system 600 may have more or fewer components than shown, may combine additional components not depicted in the example embodiment of Figure 6, and/or computing system 600 may have a different configuration or arrangement of the components depicted in Figure 6. The various components shown in Figure 6 may be implemented in hardware,

software, or a combination of both hardware and software, including one or more signal processing and/or application specific integrated circuits.

[0084] Further, the steps in the processing methods described herein may be implemented by running one or more functional modules in information processing apparatus such as general-purpose processors or application specific chips, such as ASICs, FPGAs, PLDs, or other appropriate devices. These modules, combinations of these modules, and/or their combination with general hardware are all included within the scope of protection of embodiments of the invention.

[0085] Geologic interpretations, models and/or other interpretation aids may be refined in an iterative fashion; this concept is applicable to embodiments of the present methods discussed herein. This can include use of feedback loops executed on an algorithmic basis, such as at a computing device (e.g., computing system 600, Figure 6), and/or through manual control by a user who may make determinations regarding whether a given step, action, template, model, or set of curves has become sufficiently accurate for the evaluation of the subsurface three-dimensional geologic formation under consideration.

[0086] The foregoing description, for purpose of explanation, has been described with reference to specific embodiments. However, the illustrative discussions above are not intended to be exhaustive or to limit embodiments of the invention to the precise forms disclosed. Many modifications and variations are possible in view of the above teachings. Moreover, the order in which the elements of the methods are illustrated and described may be re-arranged, and/or two or more elements may occur simultaneously. The embodiments were chosen and described in order to best explain the principles of the invention and its practical applications, to thereby enable others skilled in the art to best utilize the invention and various embodiments with various modifications as are suited to the particular use contemplated.

CLAIMS

What is claimed is:

1. A multi-stage source separation method for processing time-lapse seismic survey data for marine and/or land environments, the method comprising:
 - receiving baseline survey data;
 - receiving monitoring survey data, wherein the monitoring survey data is acquired after the baseline survey data;
 - modifying the baseline survey data to produce processed baseline survey data;
 - generating associated interference noise based upon the processed baseline survey data;
 - removing interference from the monitoring survey data based upon the associated interference noise to produce residual model data;
 - generating a clean signal model based upon the residual model data; and
 - combining the processed baseline survey data and the clean signal model to produce a final clean signal model.
2. The method of claim 1, comprising:
 - generating a clean signal based upon the baseline survey data; and
 - projecting the baseline survey data to locations of the monitoring survey data to produce an estimate of the clean signal at the locations of the monitoring survey data, wherein projecting the baseline survey data includes projecting the clean signal.
3. The method of claim 1, comprising determining one or more operators based upon the baseline survey data, the monitoring survey data, or both, wherein the baseline survey data is modified by applying the one or more operators to the estimate of the clean signal.
4. The method of claim 3, wherein the one or more operators include a de-bubble operator and a global source matching operator.
5. The method of claim 1, wherein the baseline survey data does not match the monitoring survey data, and wherein the processed baseline survey data matches the monitoring survey data.

6. The method of claim 1, wherein the associated interference noise is also generated based upon a blending operator, and wherein the blending operator models the interference from simultaneous sources that generate the monitoring survey data.
7. The method of claim 1, wherein the interference is removed by:
 - adding the associated interference noise to the processed baseline survey data to produce estimated monitoring survey data; and
 - subtracting the estimated monitoring survey data from the monitoring survey data to produce the residual model data.
8. The method of claim 1, wherein the residual model data includes a residual signal and the associated interference noise of the monitoring survey data that is not explained by the baseline survey data.
9. The method of claim 1, comprising displaying the final clean signal model.
10. The method of claim 1, comprising performing a physical wellsite action in response to the final clean signal model.
11. A computing system, comprising:
 - one or more processors; and
 - a memory system including one or more non-transitory computer-readable media storing instructions that, when executed by at least one of the one or more processors, cause the computing system to perform operations, the operations including:
 - receiving baseline survey data;
 - generating a clean signal based upon the baseline survey data, wherein the clean signal is generated using seismic processing;
 - receiving monitoring survey data, wherein the monitoring survey data is acquired after the baseline survey data;

projecting the clean signal to locations of the monitoring survey data to produce an estimate of the clean signal at the locations of the monitoring survey data;

determining one or more operators based upon the baseline survey data, the monitoring survey data, or both, wherein the one or more operators include a de-bubble operator and a global source matching operator;

modifying the baseline survey data to produce processed baseline survey data, wherein the baseline survey data is modified using time-lapse processing, wherein the baseline survey data is modified by applying the one or more operators to the estimate of the clean signal, wherein the baseline survey data does not match the monitoring survey data, and wherein the processed baseline survey data matches the monitoring survey data;

generating associated interference noise based upon the processed baseline survey data, wherein the associated interference noise is also generated based upon a blending operator, wherein the blending operator models interference from simultaneous sources that generate the monitoring survey data;

removing the interference from the monitoring survey data based upon the associated interference noise to produce residual model data;

generating a clean signal model based upon the residual model data, wherein the clean signal model is generated using a noise attenuation framework, and wherein the noise attenuation framework includes a source separation technology;

combining the processed baseline survey data and the clean signal model to produce a final clean signal model for the monitoring survey data; and

displaying the final clean signal model.

12. The computing system of claim 11, wherein the clean signal is projected using an acquisition configuration of the monitoring survey data, and wherein the clean signal is projected using interpolation or regularization.

13. The computing system of claim 11, wherein the operations further include extracting a far-field source signature model from the monitoring survey data, wherein the one or more operators are also determined based upon the far-field source signature model.

14. The computing system of claim 11, wherein the operations further include:
extracting global positioning system (GPS) time information and source-receiver information from the monitoring survey data; and
mapping the GPS time information and the source-receiver information to the baseline survey data to produce mapped baseline survey data, wherein the associated interference noise is also generated based upon the mapped baseline survey data.
15. The computing system of claim 11, wherein the interference is removed by:
adding the associated interference noise to the processed baseline survey data to produce estimated monitoring survey data; and
subtracting the estimated monitoring survey data from the monitoring survey data to produce the residual model data, wherein the residual model data includes a residual signal and the associated interference noise of the monitoring survey data that is not explained by the baseline survey data.
16. A non-transitory computer-readable medium storing instructions that, when executed by one or more processors of a computing system, cause the computing system to perform operations, the operations comprising:
receiving baseline survey data;
generating a clean signal based upon the baseline survey data, wherein the clean signal is generated using seismic processing, and wherein the clean signal is generated in response to the baseline survey data being acquired using simultaneous shooting;
receiving monitoring survey data, wherein the monitoring survey data is acquired after the baseline survey data;
projecting the clean signal to locations of the monitoring survey data to produce an estimate of the clean signal at the locations of the monitoring survey data, wherein the clean signal is projected using an acquisition configuration of the monitoring survey data, and wherein the clean signal is projected using interpolation or regularization;
extracting a far-field source signature model from the monitoring survey data;
determining one or more operators based upon the baseline survey data, the monitoring survey data, or both, wherein the one or more operators are based upon the baseline survey data

and the far-field signature model, and wherein the one or more operators include a de-bubble operator and a global source matching operator;

modifying the baseline survey data to produce processed baseline survey data, wherein the baseline survey data is modified using time-lapse processing, wherein the baseline survey data is modified by applying the one or more operators to the estimate of the clean signal, wherein the baseline survey data does not match the monitoring survey data, and wherein the processed baseline survey data matches the monitoring survey data;

extracting global positioning system (GPS) time information and source-receiver information from the monitoring survey data;

mapping the GPS time information and the source-receiver information to the baseline survey data to produce mapped baseline survey data;

generating associated interference noise based upon the processed baseline survey data, the mapped baseline survey data, and a blending operator, wherein the blending operator models interference from simultaneous sources that generate the monitoring survey data;

removing the interference from the monitoring survey data based upon the associated interference noise to produce residual model data, wherein the interference is removed by:

adding the associated interference noise to the processed baseline survey data to produce estimated monitoring survey data; and

subtracting the estimated monitoring survey data from the monitoring survey data to produce the residual model data, wherein the residual model data includes a residual signal and the associated interference noise of the monitoring survey data that is not explained by the baseline survey data;

generating a clean signal model based upon the residual model data, wherein the clean signal model is generated using a noise attenuation framework, and wherein the noise attenuation framework includes a source separation technology;

combining the processed baseline survey data and the clean signal model to produce a final clean signal model for the monitoring survey data; and

displaying the final clean signal model.

17. The non-transitory computer-readable medium of claim 16, wherein the baseline survey data, the monitoring survey data, or both include seismic data that is acquired using sequential or simultaneous shooting on a regular or irregular grid.

18. The non-transitory computer-readable medium of claim 16, wherein the operations further include performing a wellsite action in response to the final clean signal model.

19. The non-transitory computer-readable medium of claim 18, wherein performing the wellsite action includes generating and transmitting a signal that causes a physical action to occur at a wellsite.

20. The non-transitory computer-readable medium of claim 19, wherein the physical action includes selecting where to drill a wellbore, drilling the wellbore, varying a weight and/or torque on a drill bit that is drilling the wellbore, varying a drilling trajectory of the wellbore, varying a concentration and/or flow rate of a fluid pumped into the wellbore, or a combination thereof.

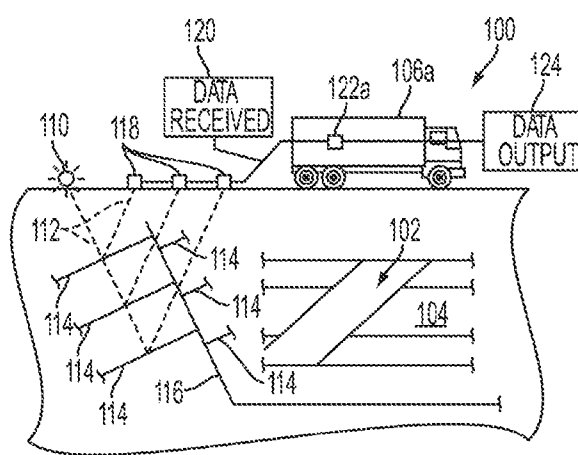


FIG. 1A

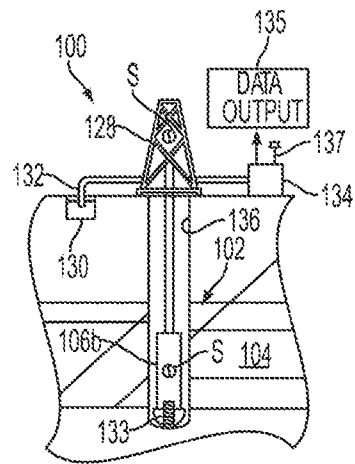


FIG. 1B

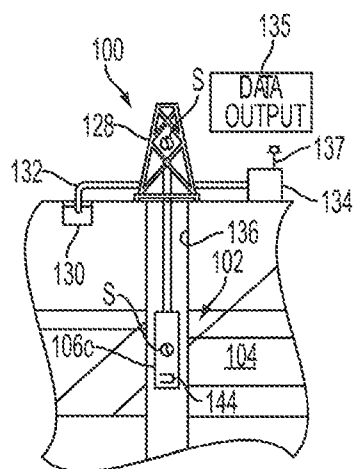


FIG. 1C

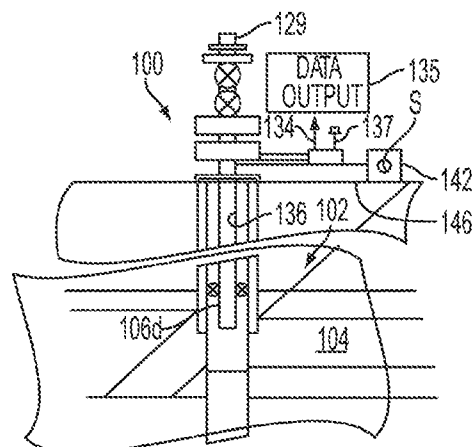


FIG. 1D

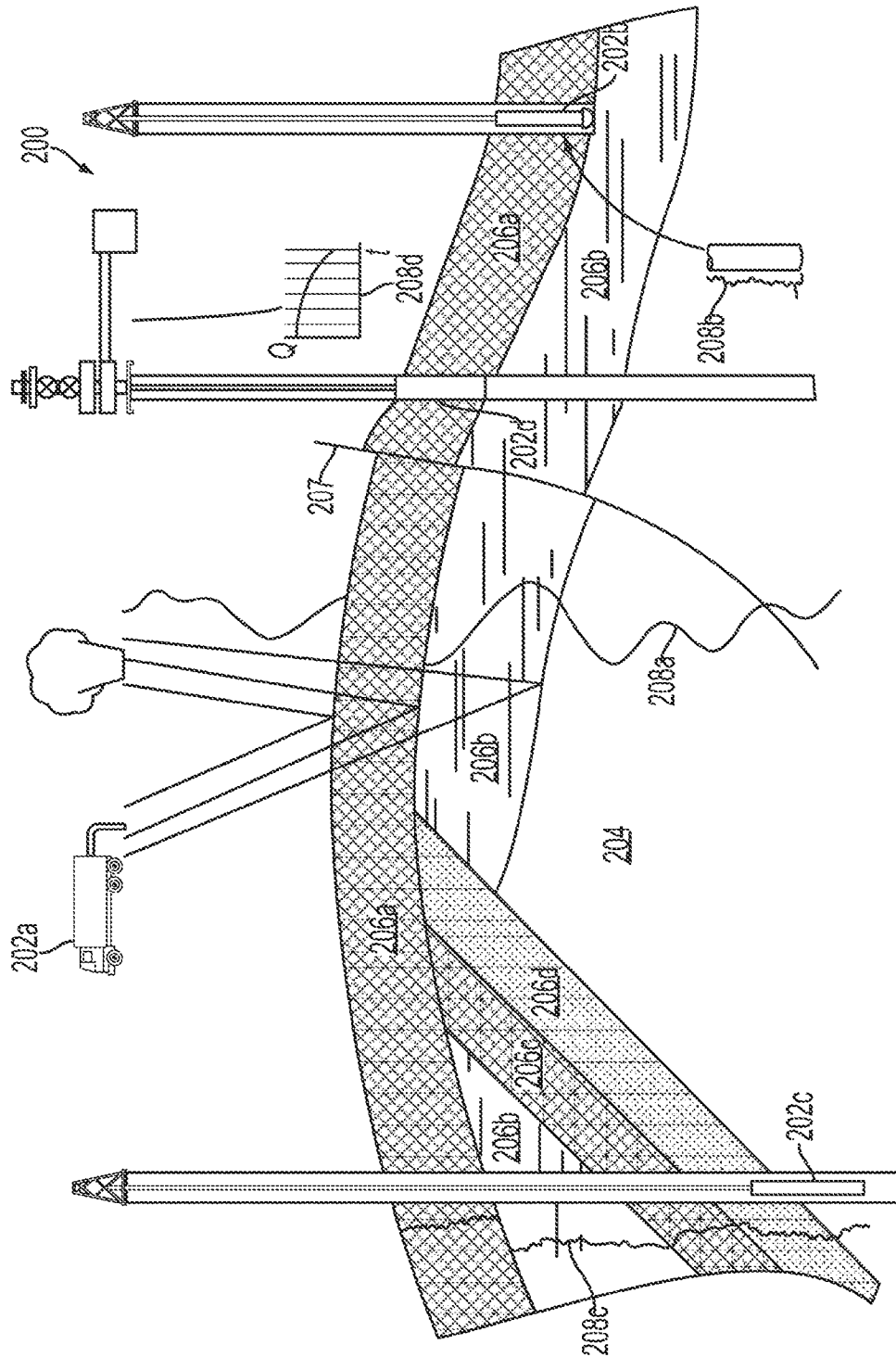


FIG. 2

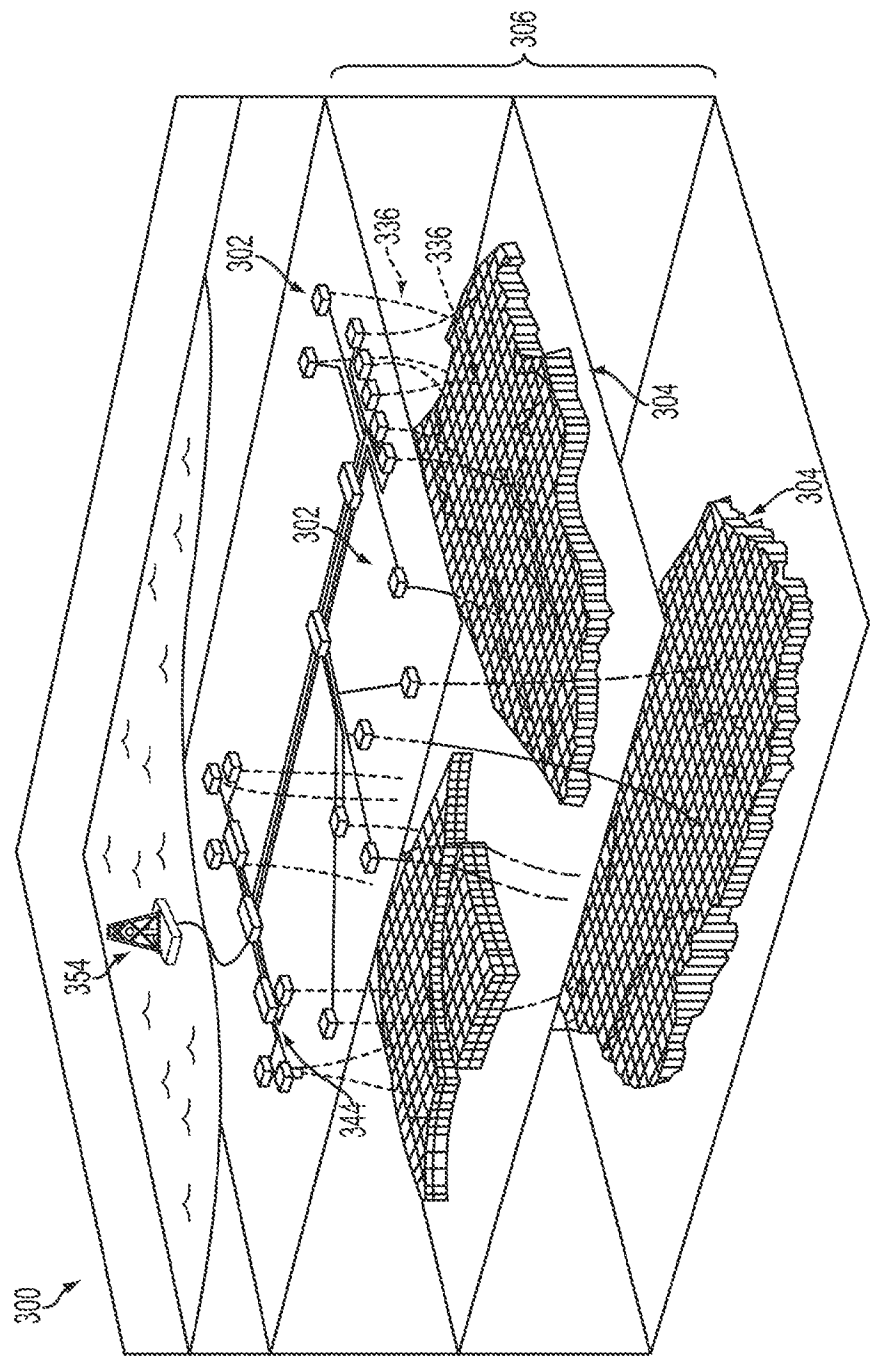


FIG. 3A

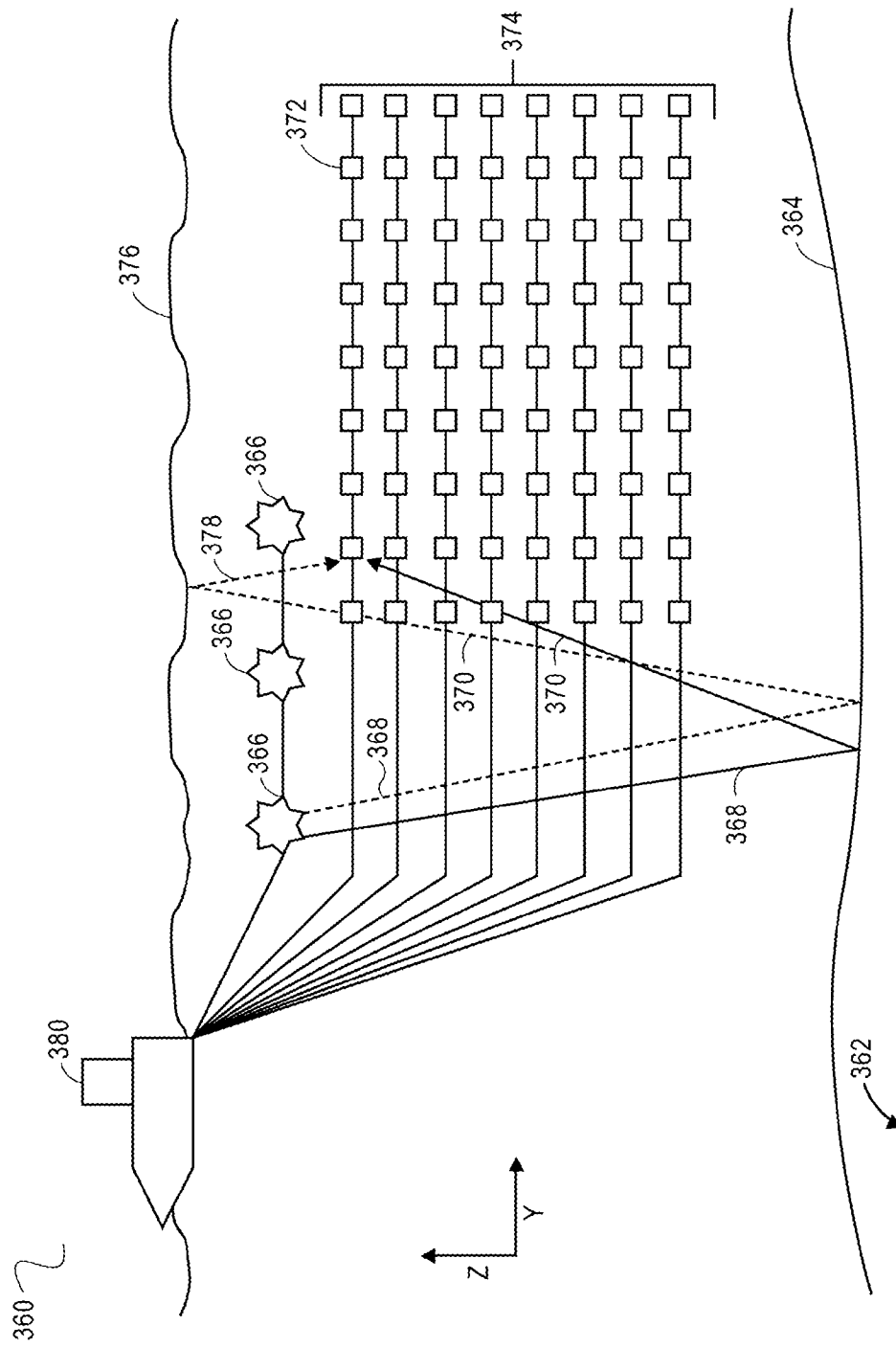
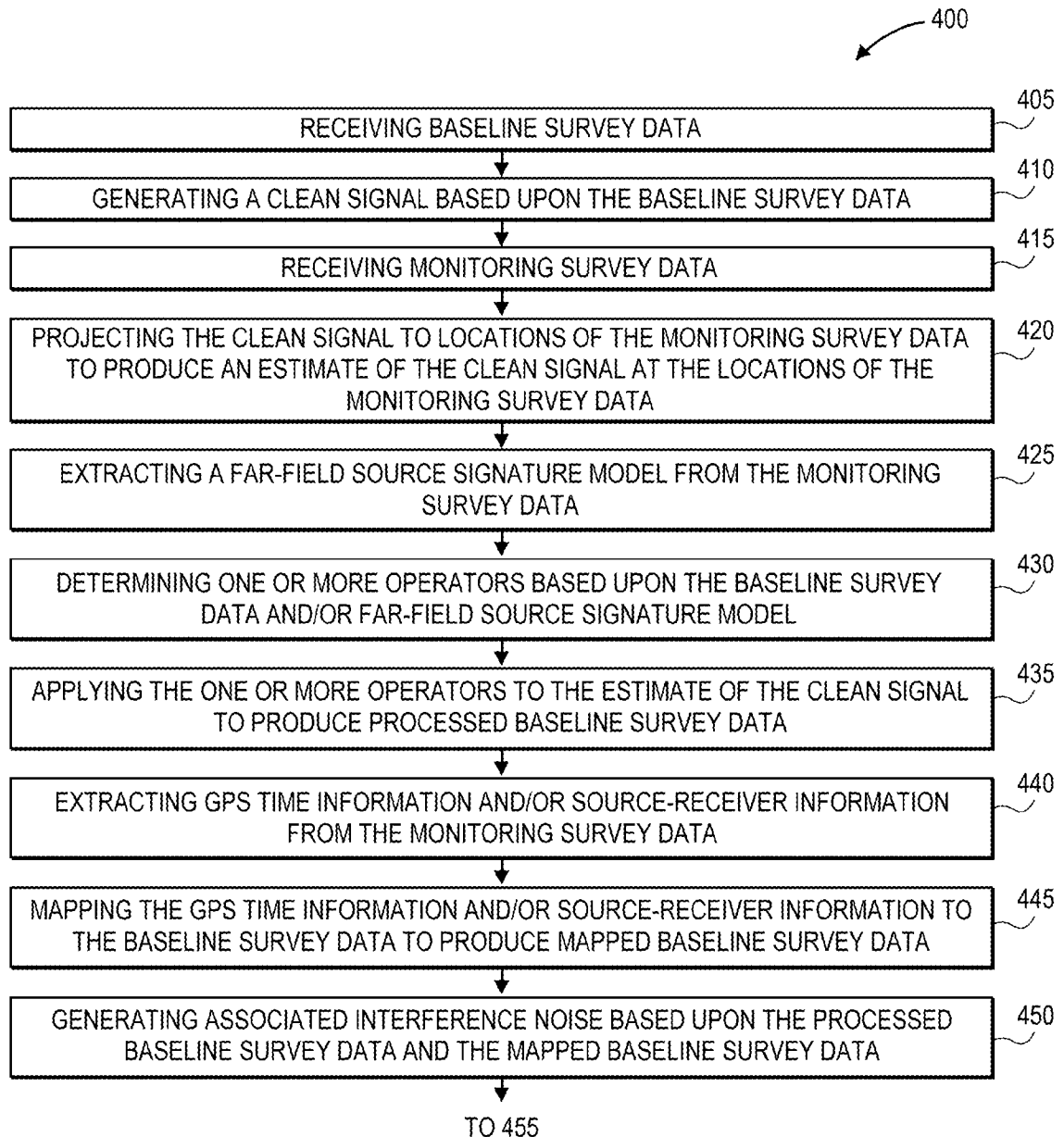
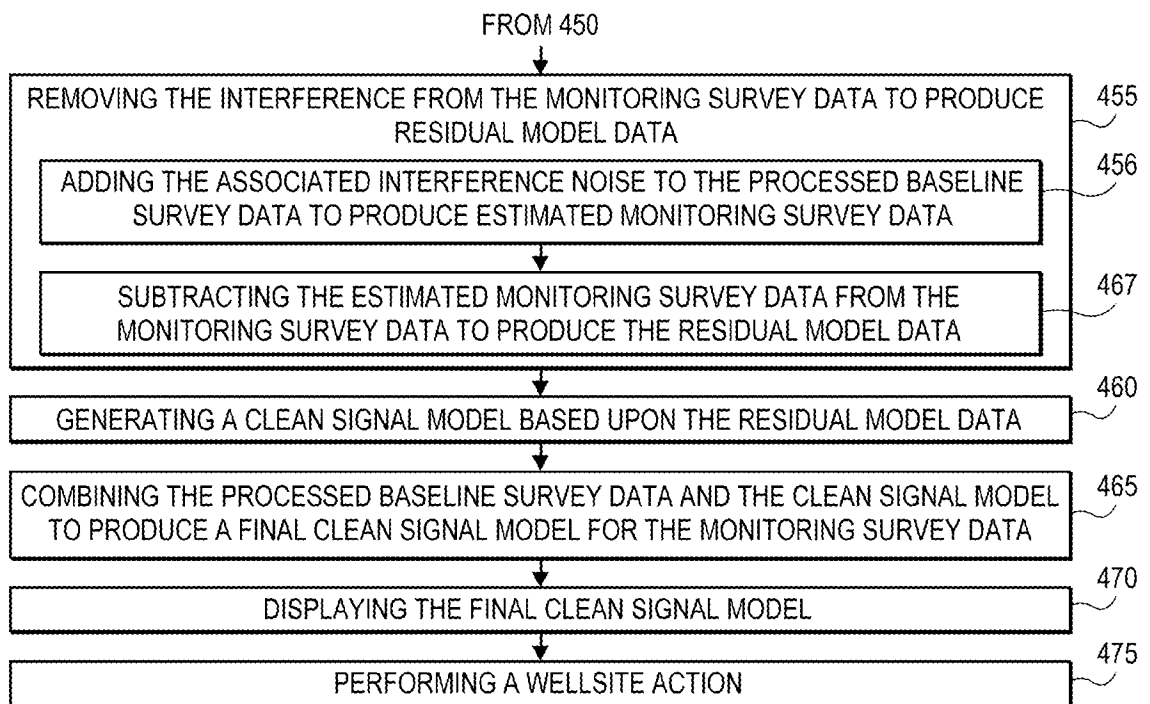


FIG. 3B

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**FIG. 4A**

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**FIG. 4B**

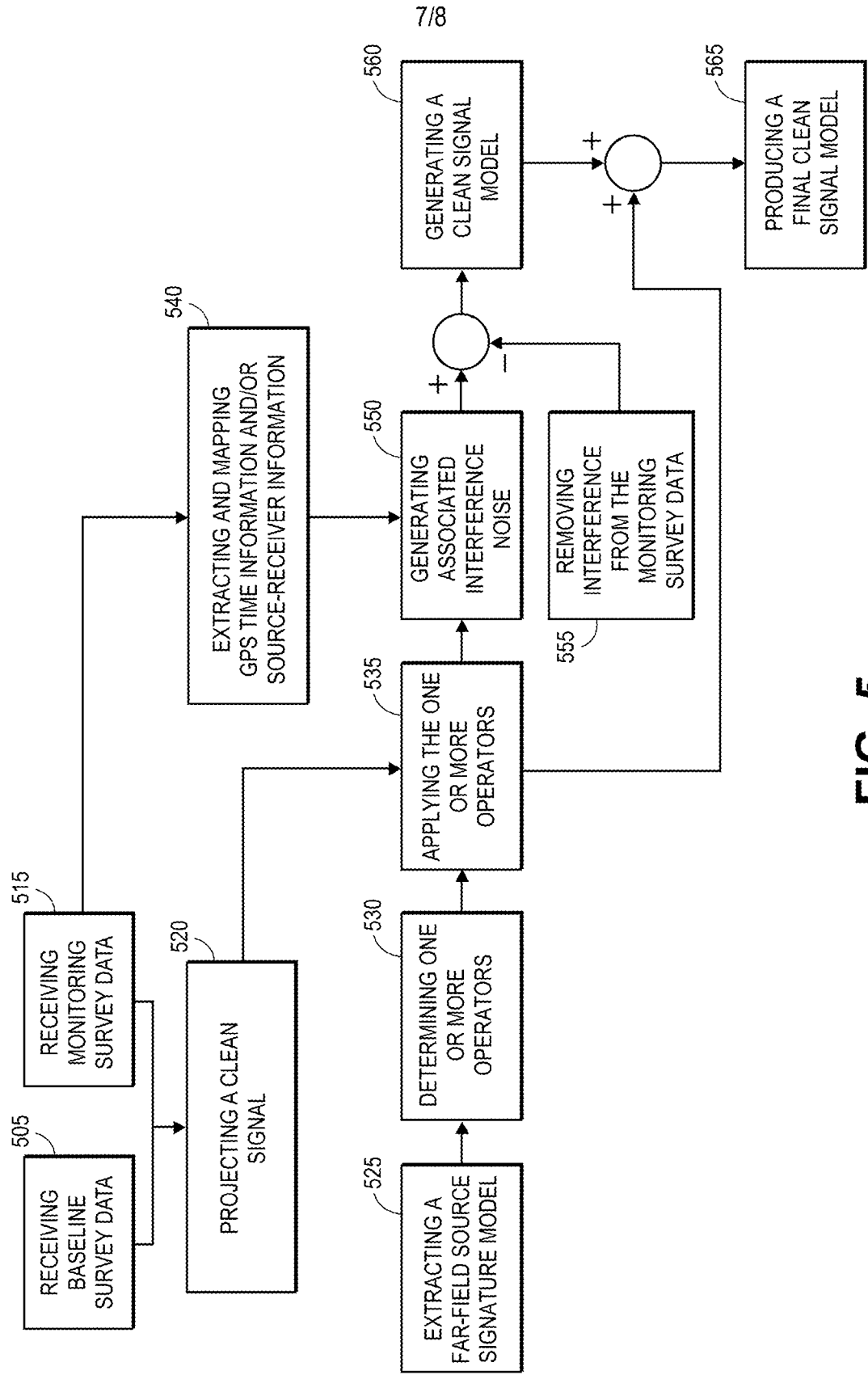
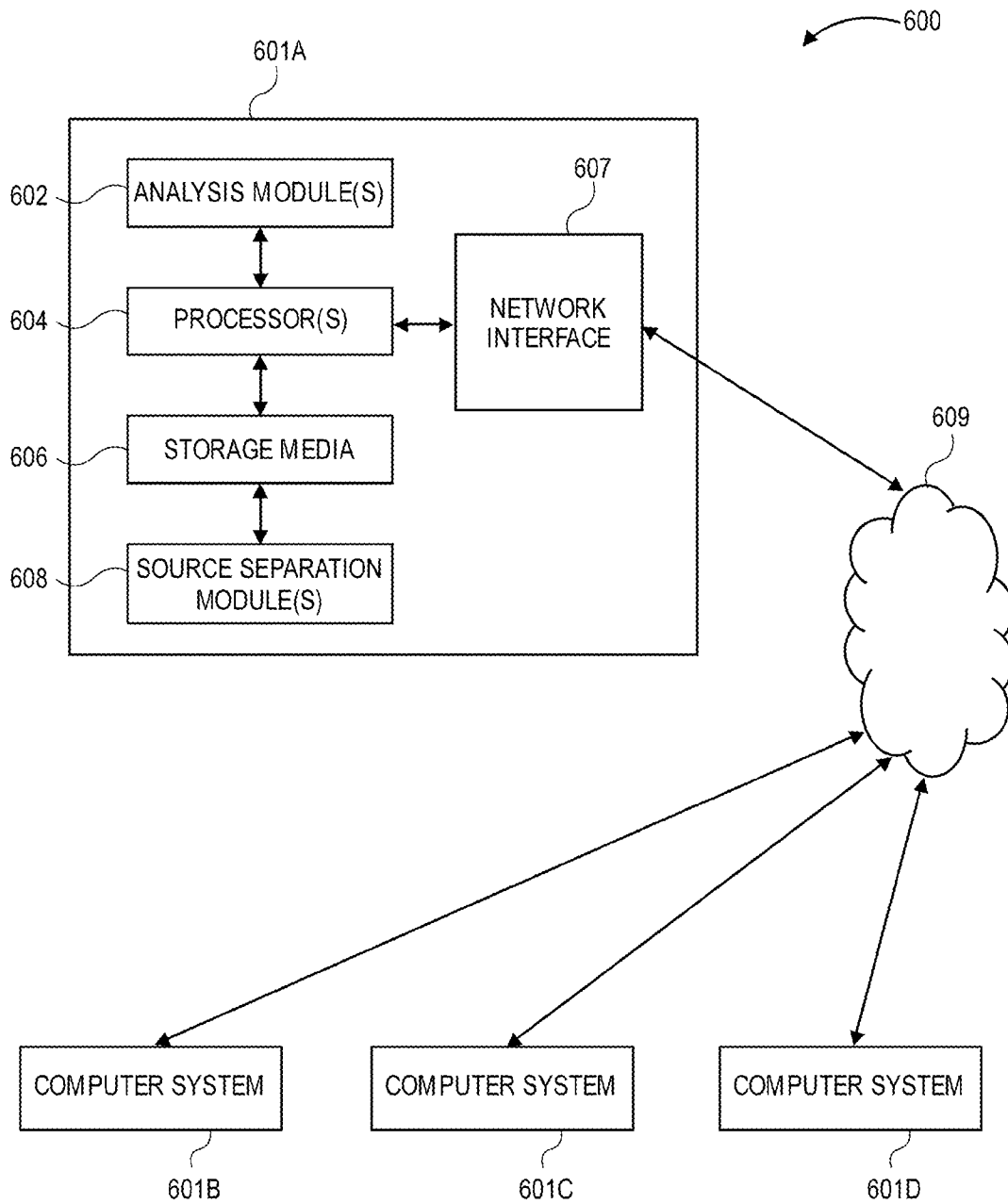


FIG. 5

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**FIG. 6**

INTERNATIONAL SEARCH REPORT

International application No.

PCT/US 23/83955

A. CLASSIFICATION OF SUBJECT MATTER

IPC - INV. G01V 1/48, G01V 1/28 (2024.01)

ADD. G01V 1/38, G01V 1/50, G01V 1/34 (2024.01)

CPC - INV. G01V 1/48, G01V 1/28

ADD. G01V 1/3808, G01V 1/50, G01V 1/34

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)

See Search History document

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

See Search History document

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

See Search History document

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X --- Y	US 2016/0187513 A1 (CGG Services SA) 30 June 2016 (30.06.2016), entire document, especially Figures 1-14; para: [0010], [0047], [0050], [0055]-[0057], [0079], [0087], [0099], [0113], [0123], [0144]-[0147], [0221], [0227], [0250]	1-7, 9, 11-17 8, 10, 18-20
Y	US 2016/0209533 A1 (CGG Services SA) 21 July 2016 (21.07.2016), entire document, especially para: [0028]	8
Y	US 2019/0086568 A1 (Chevron U.S.A. Inc.) 21 March 2019 (21.03.2019), entire document, especially Figures 1-5; para: [0022]-[0028]	10, 18-20
A	US 2019/0094401 A1 (PGS Geophysical AS) 28 March 2019 (28.03.2019), entire document	1-20

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

* Special categories of cited documents:

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"D" document cited by the applicant in the international application

"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

14 March 2024 (14.03.2024)

Date of mailing of the international search report

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Name and mailing address of the ISA/US

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