



US 20160305237A1

(19) **United States**(12) **Patent Application Publication**
Klemin et al.(10) **Pub. No.: US 2016/0305237 A1**(43) **Pub. Date: Oct. 20, 2016**(54) **METHOD AND SYSTEM OF SHOWING
HETEROGENEITY OF A POROUS SAMPLE****Publication Classification**(71) Applicant: **SCHLUMBERGER TECHNOLOGY
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Nadeev**, Spring, TX (US)(51) **Int. Cl.****E21B 49/00** (2006.01)**E21B 49/02** (2006.01)**E21B 25/00** (2006.01)(52) **U.S. Cl.**CPC **E21B 49/00** (2013.01); **E21B 25/00**
(2013.01); **E21B 49/02** (2013.01); **E21B 43/20**
(2013.01)(21) Appl. No.: **15/102,233**(22) PCT Filed: **Sep. 5, 2014**(86) PCT No.: **PCT/US2014/054326**

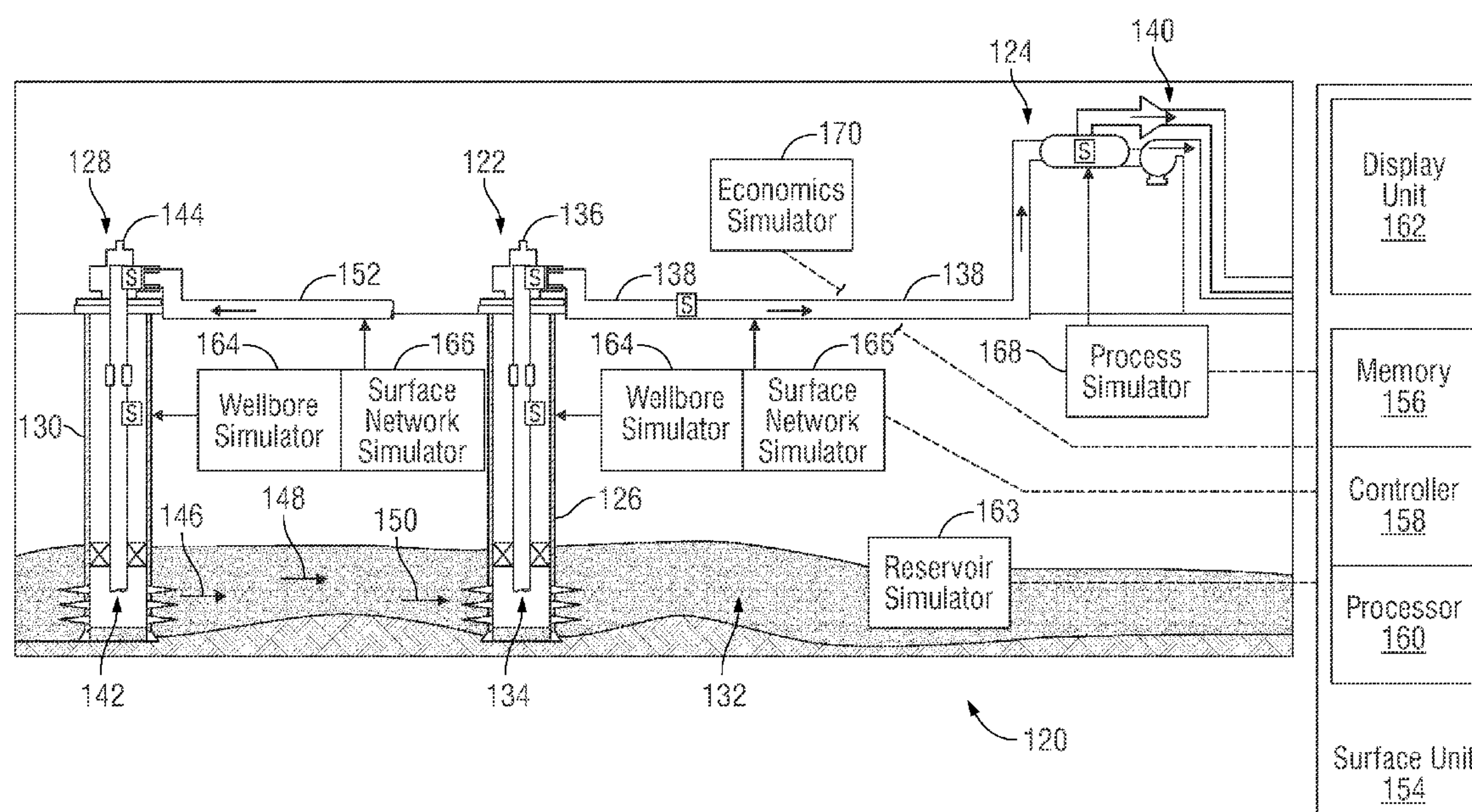
§ 371 (c)(1),

(2) Date: **Jun. 6, 2016****Related U.S. Application Data**(60) Provisional application No. 61/912,479, filed on Dec.
5, 2013.

(57)

ABSTRACT

A system and method for showing heterogeneity of a porous sample by evaluating the porous sample to generate a digital core image, performing segmentations on the digital core image using multiple approaches to obtain a segmented volume, dividing the segmented volume into one or more sub-volumes of differing size, calculating one or more petrophysical or fluid flow parameters or porosity from the one or more sub-volumes, and presenting data as a structure composed of grid blocks representing an exact representation of the one or more sub-volumes positioned according to a spatial location of the one or more sub-volumes based on selected parameters or values from the one or more petrophysical or fluid flow parameters or porosity.



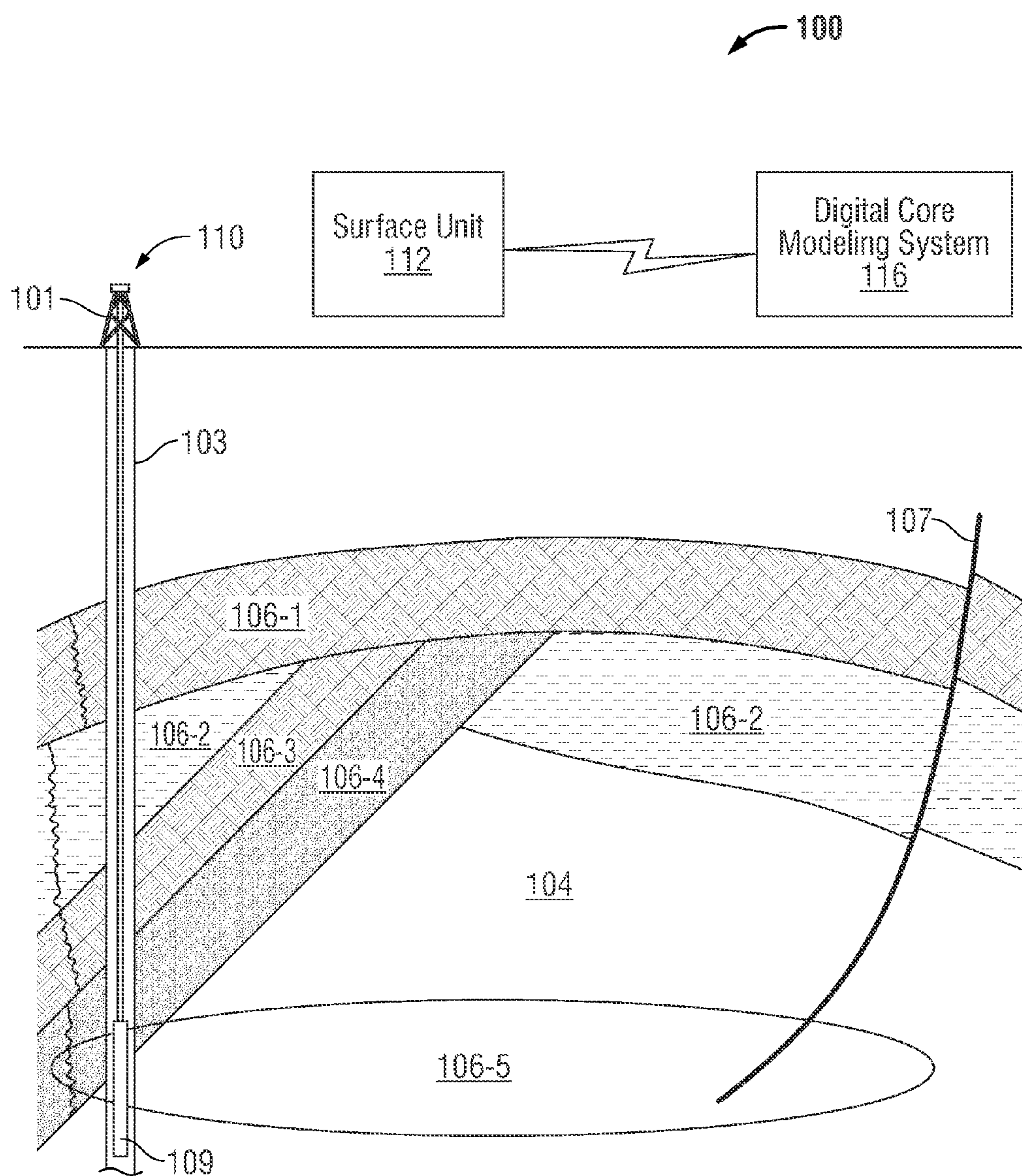


FIG. 1

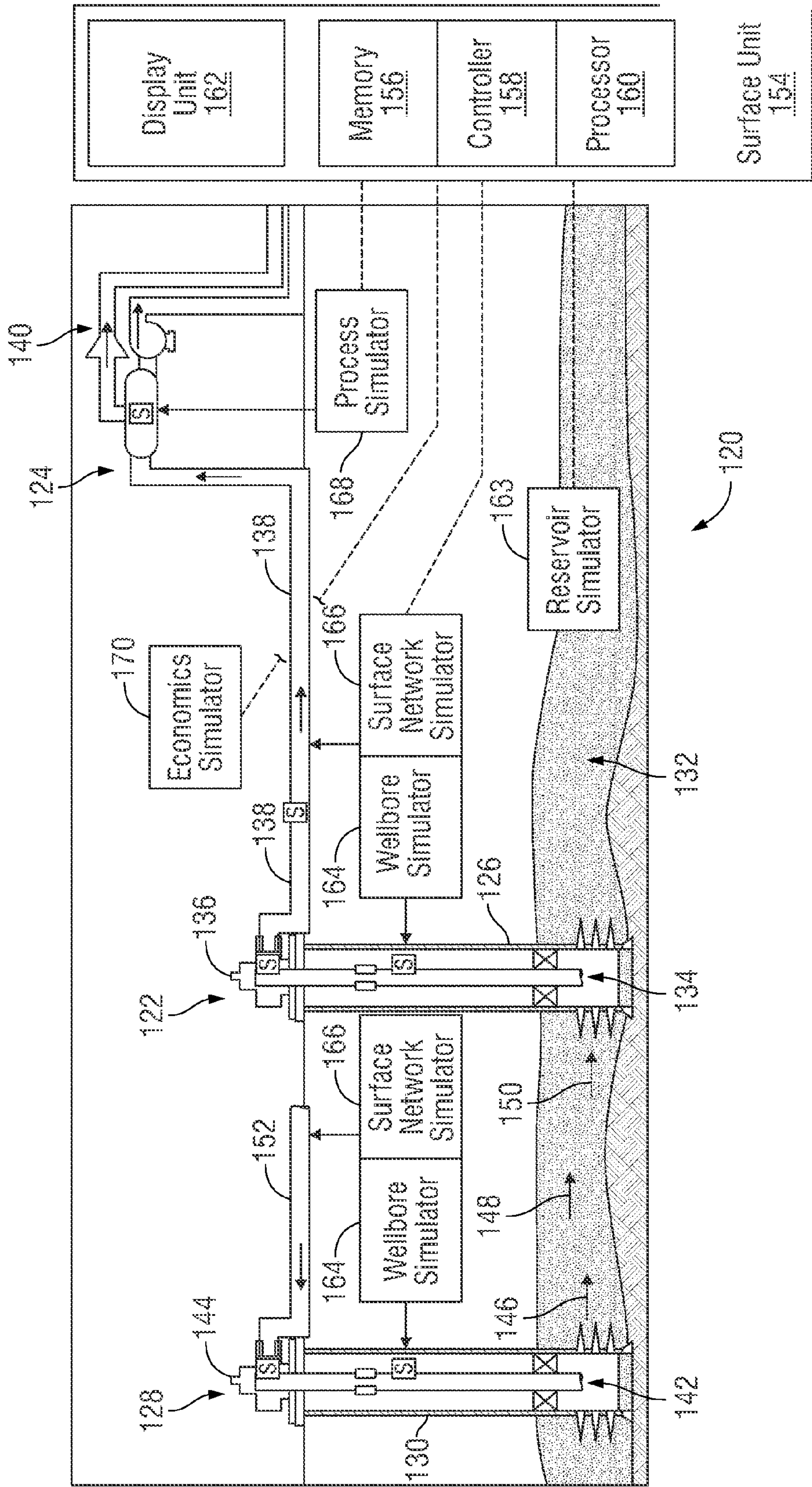


FIG. 2

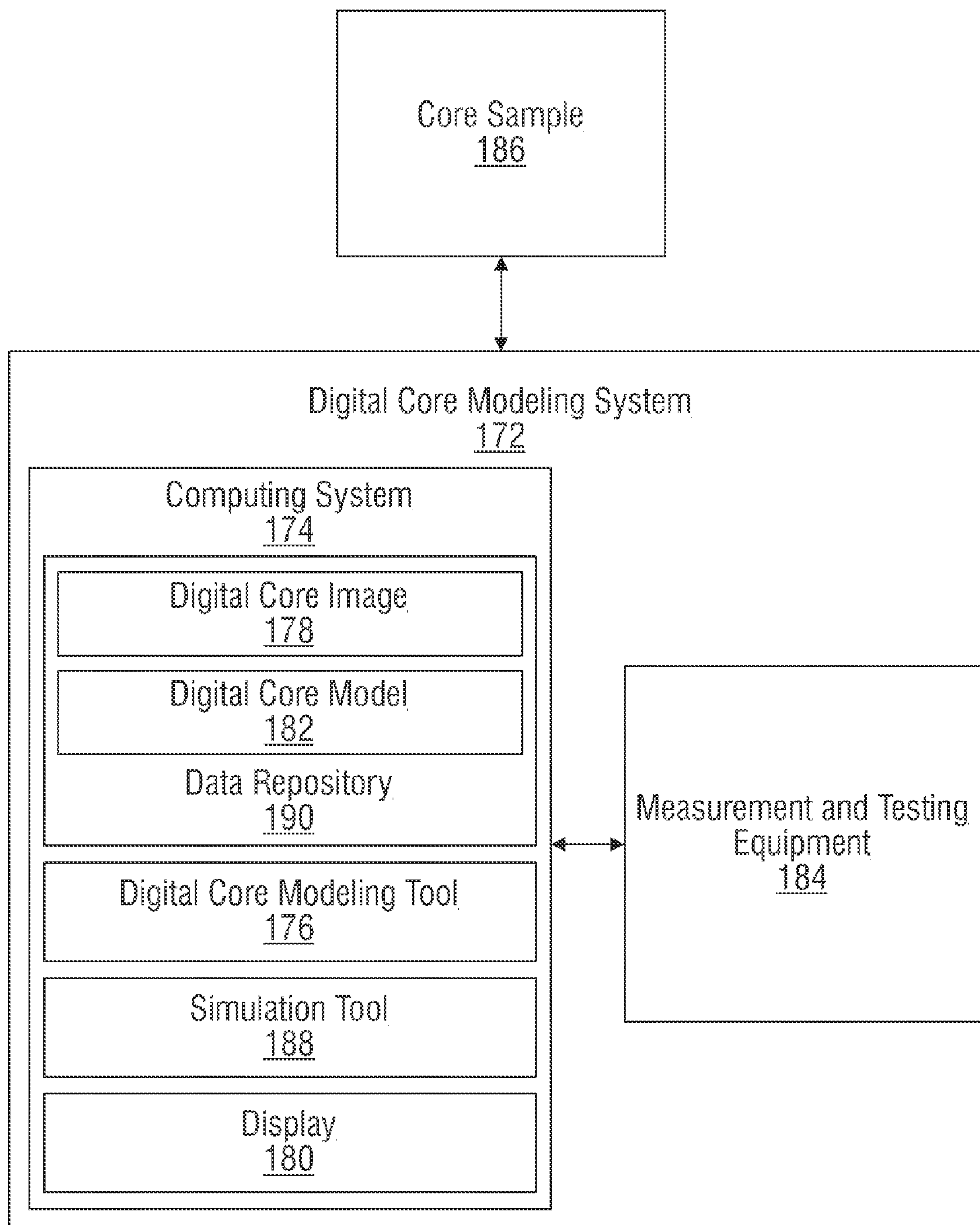


FIG. 3

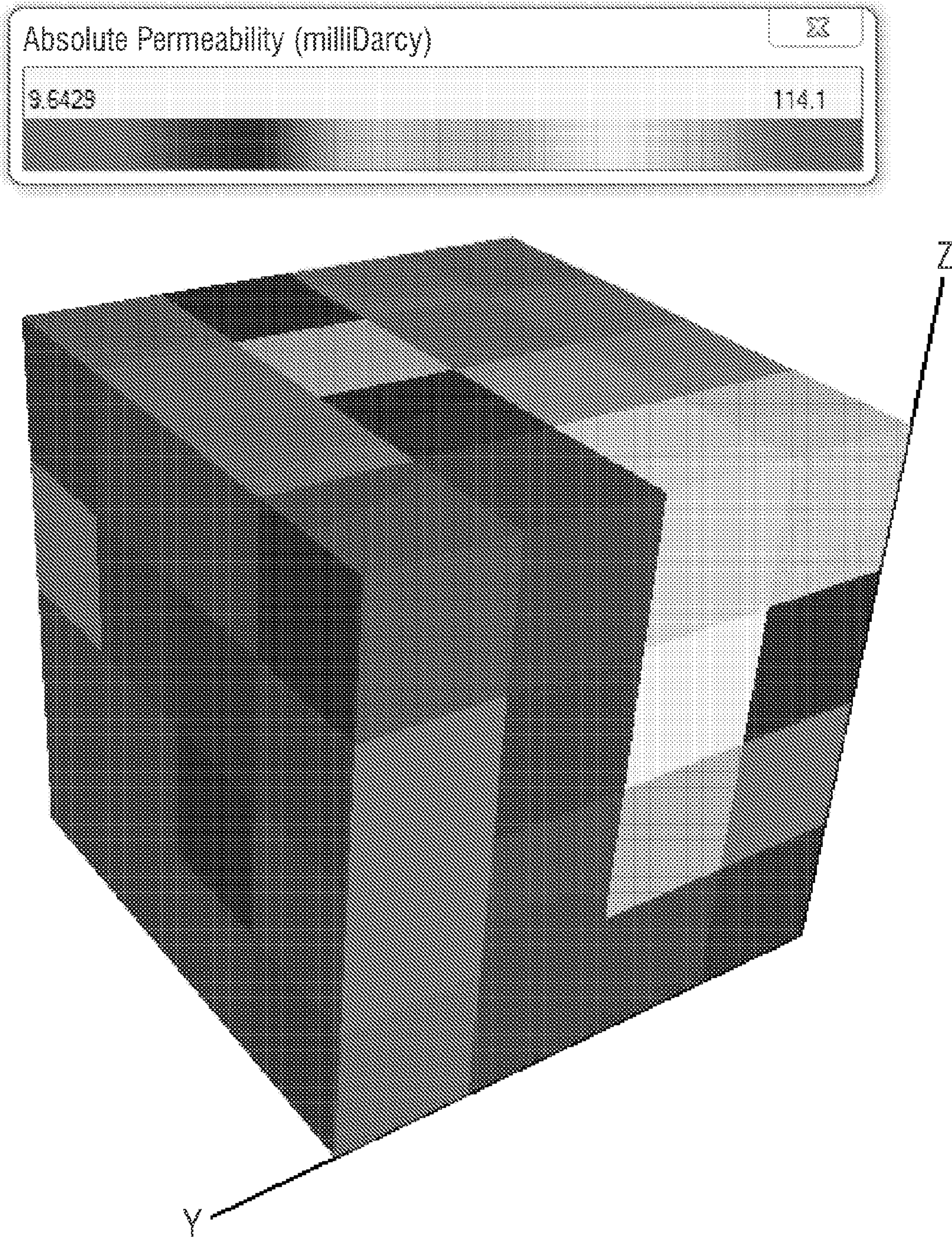


FIG. 4

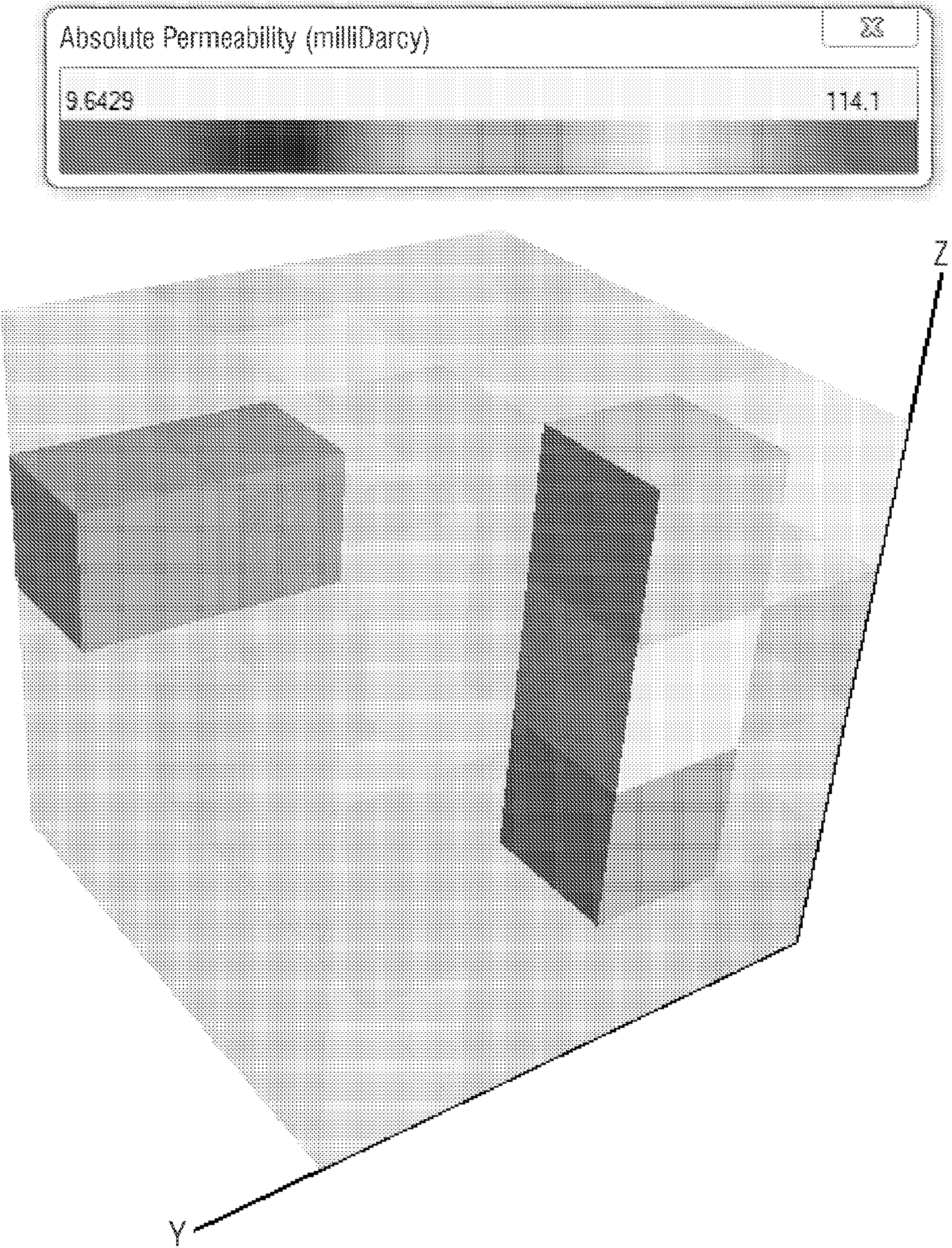


FIG. 5A

FIG. 5B

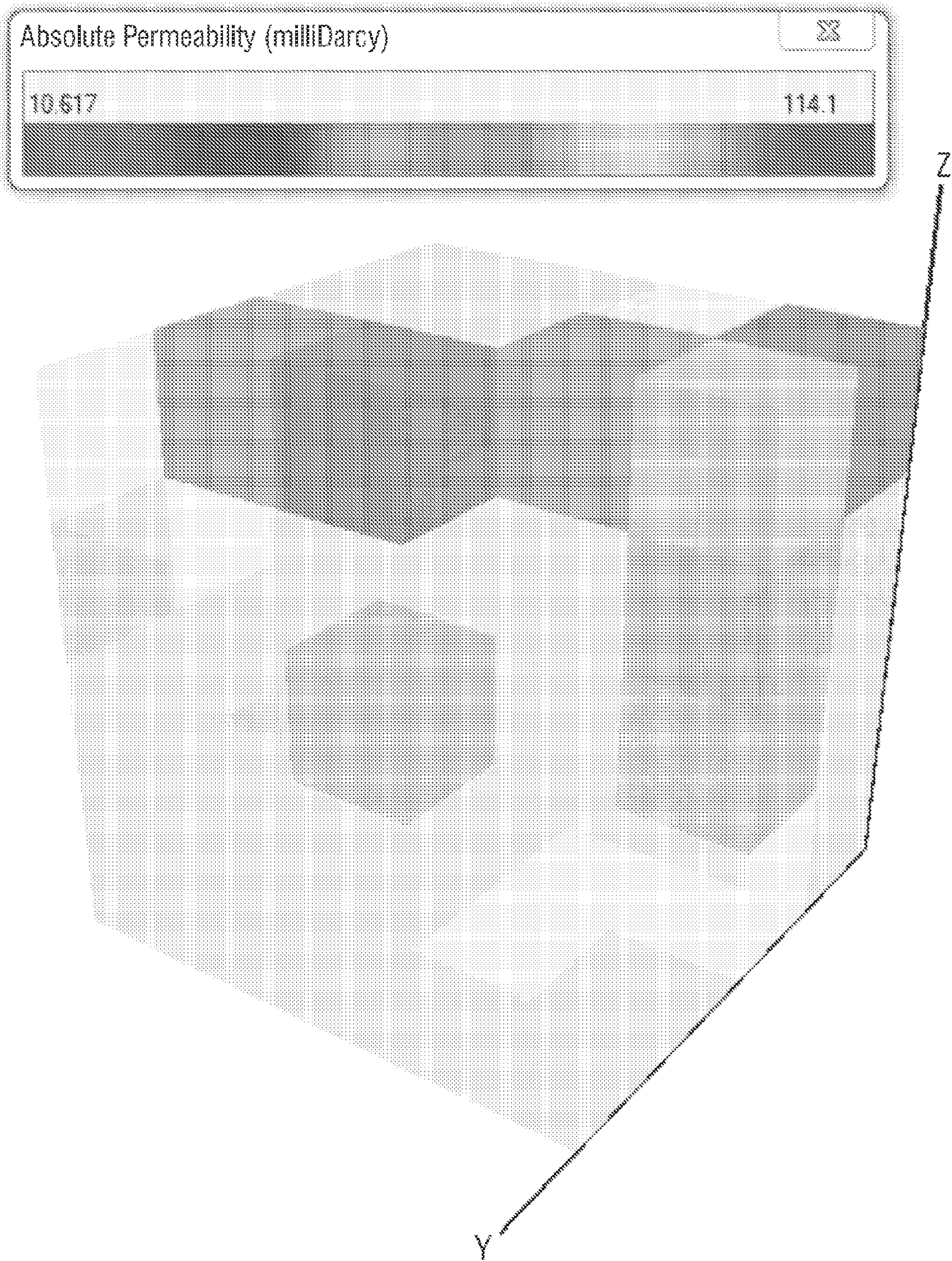


FIG. 5B

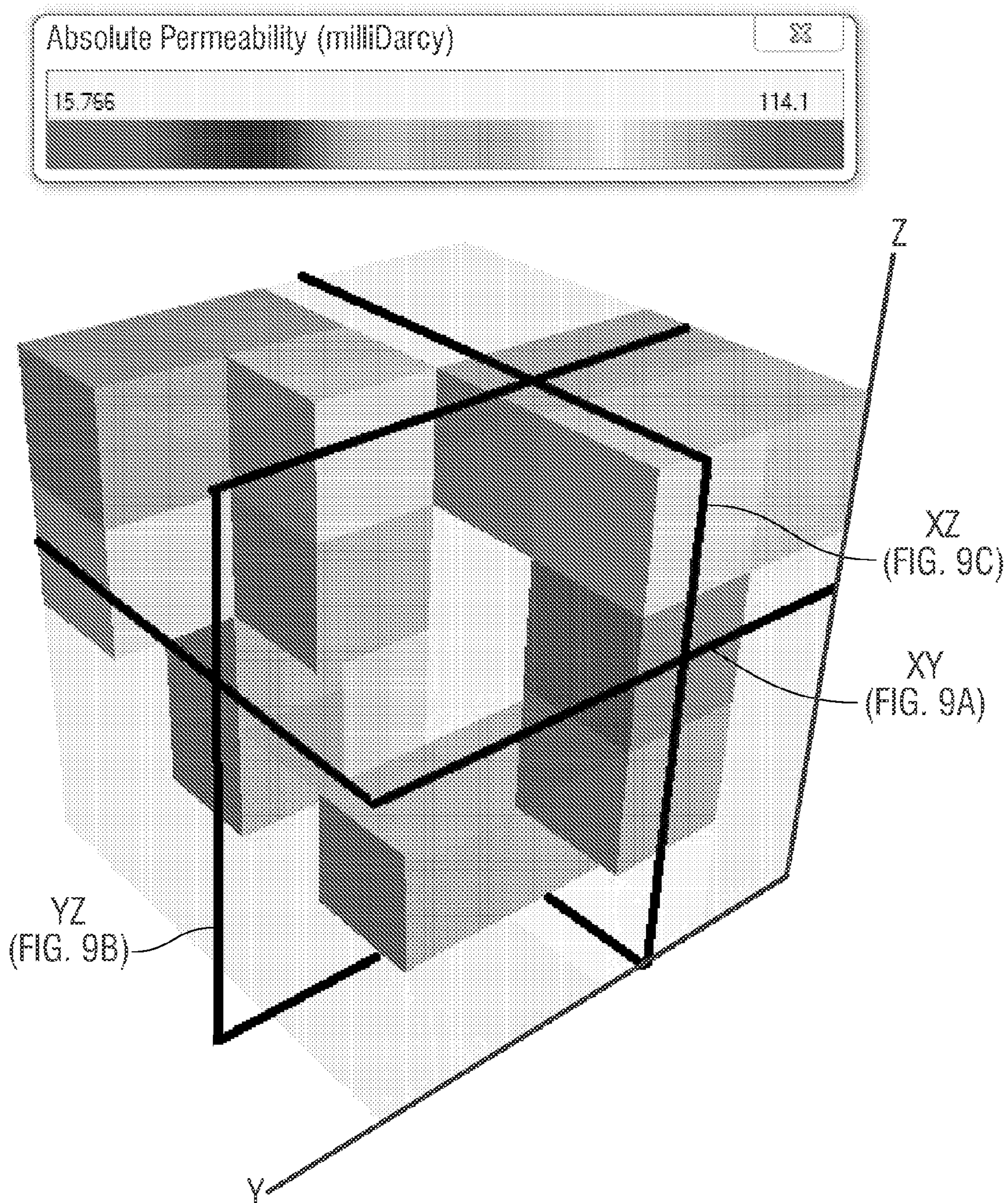


FIG. 5C

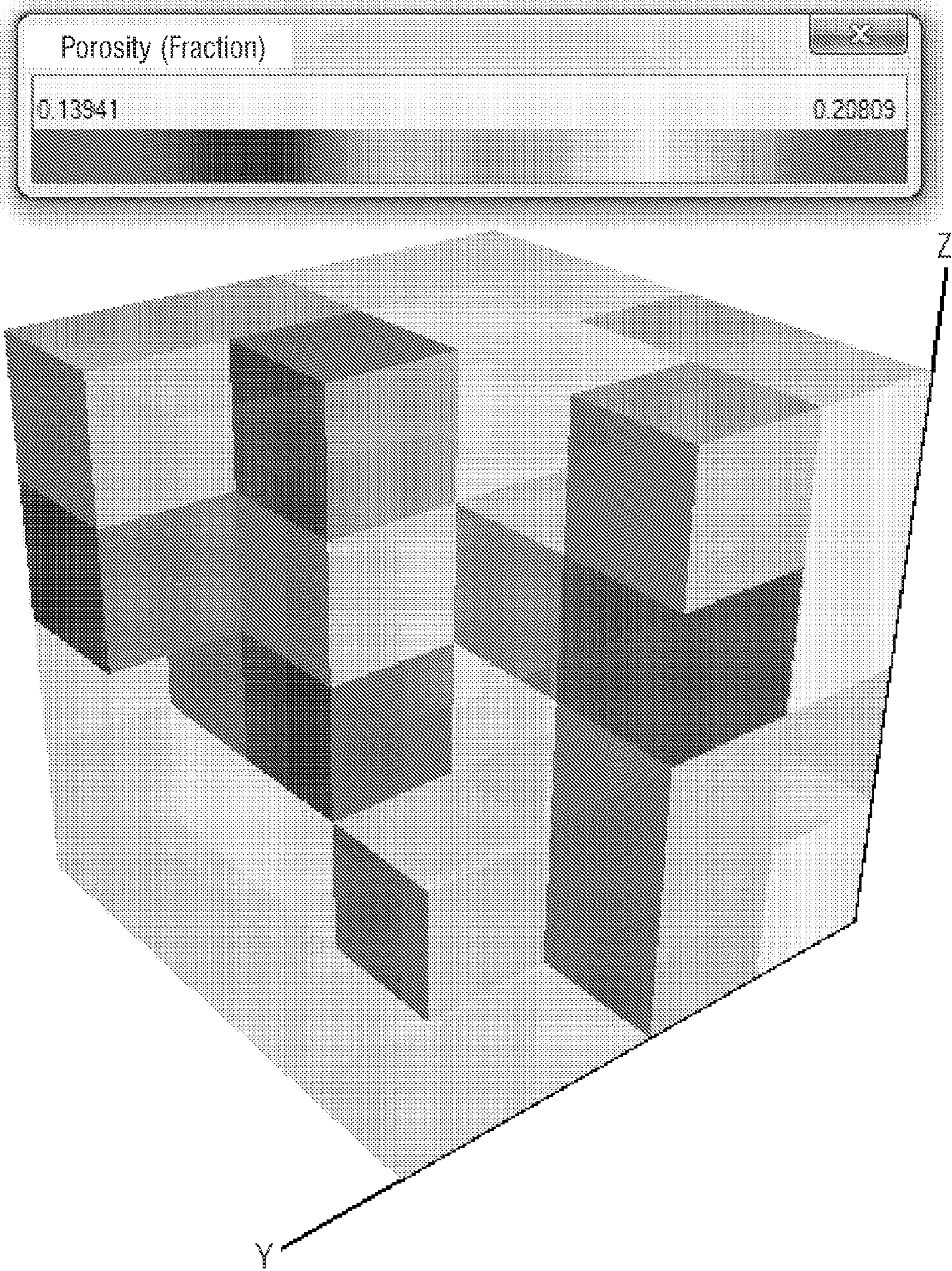


FIG. 6

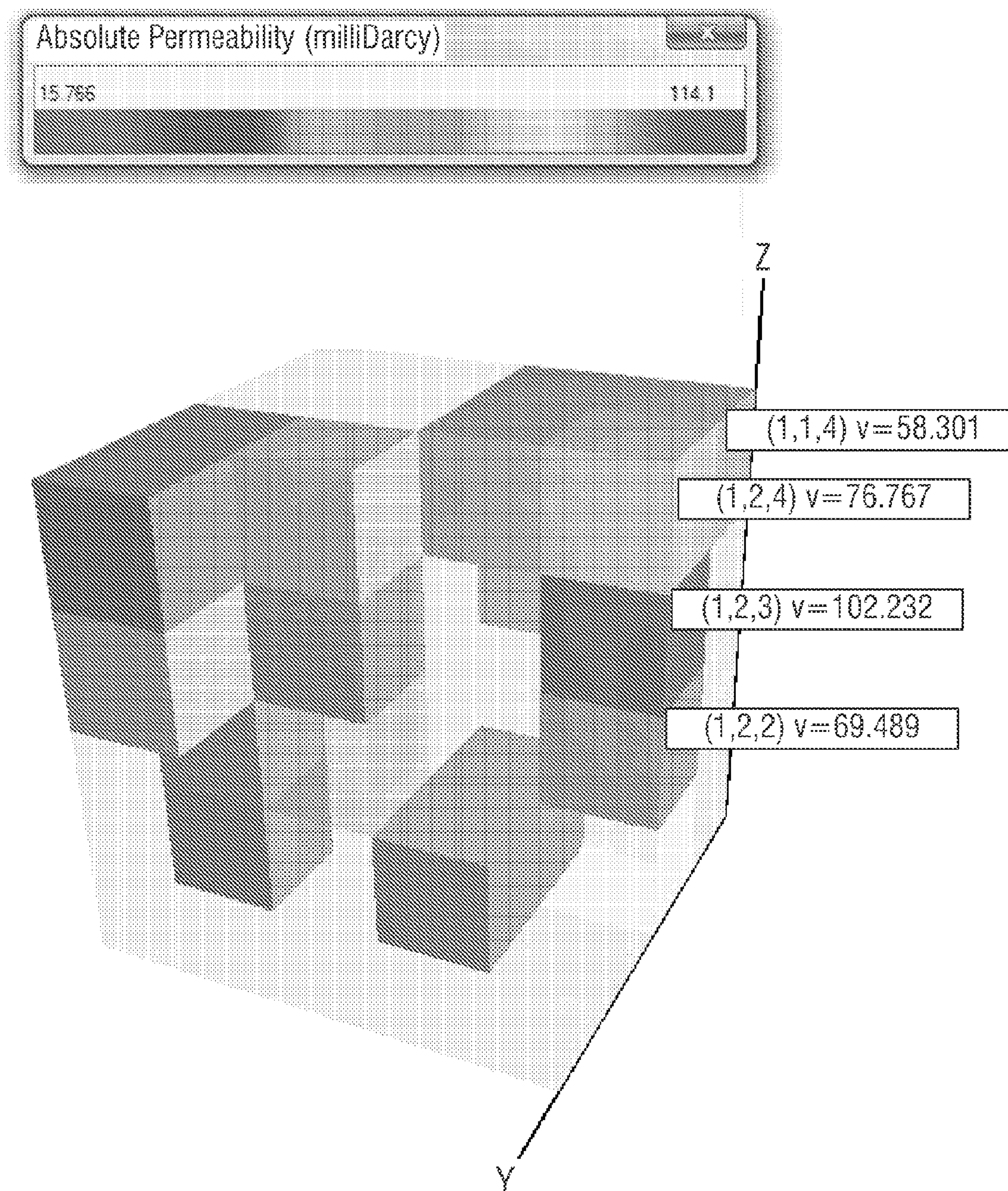


FIG. 7

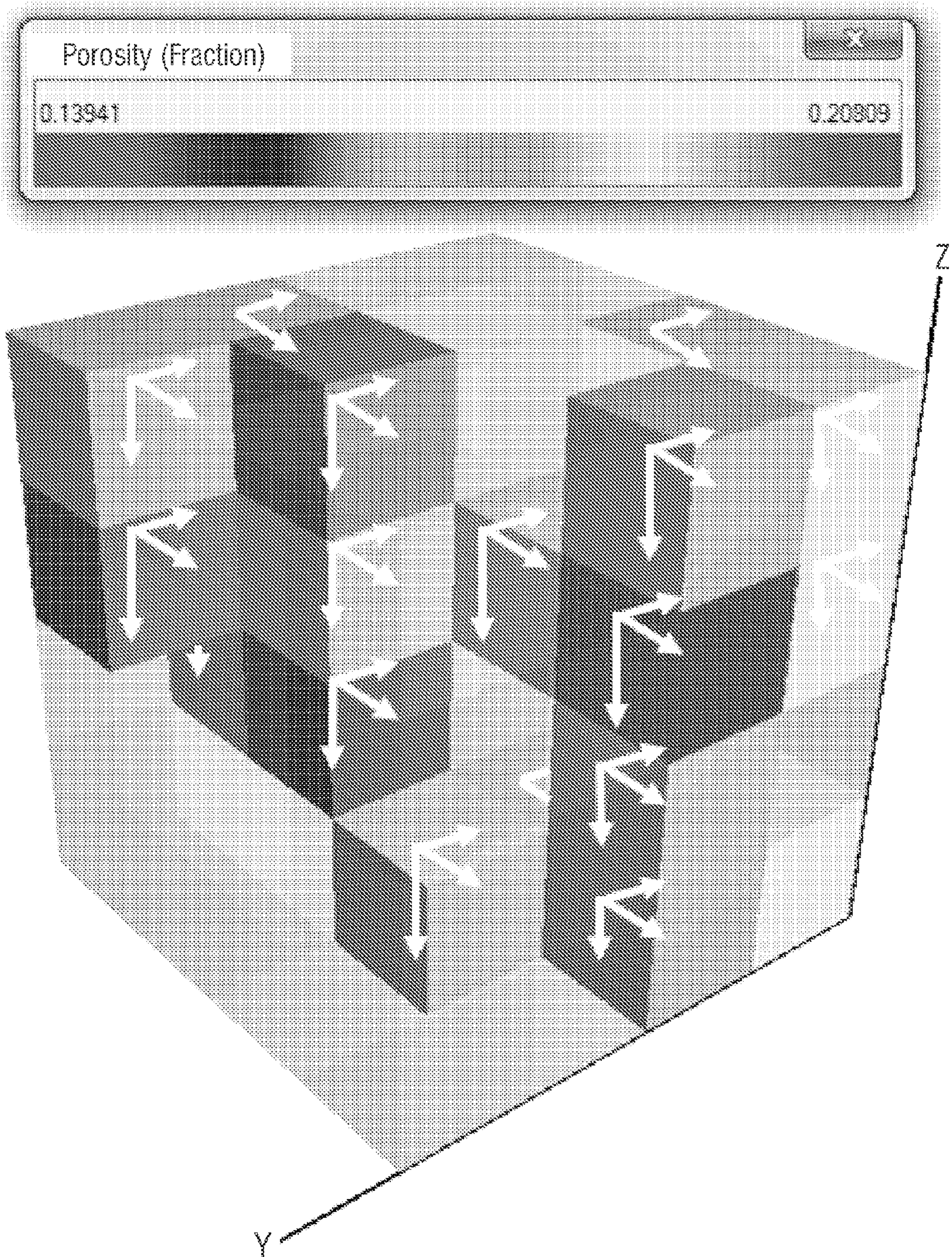


FIG. 8

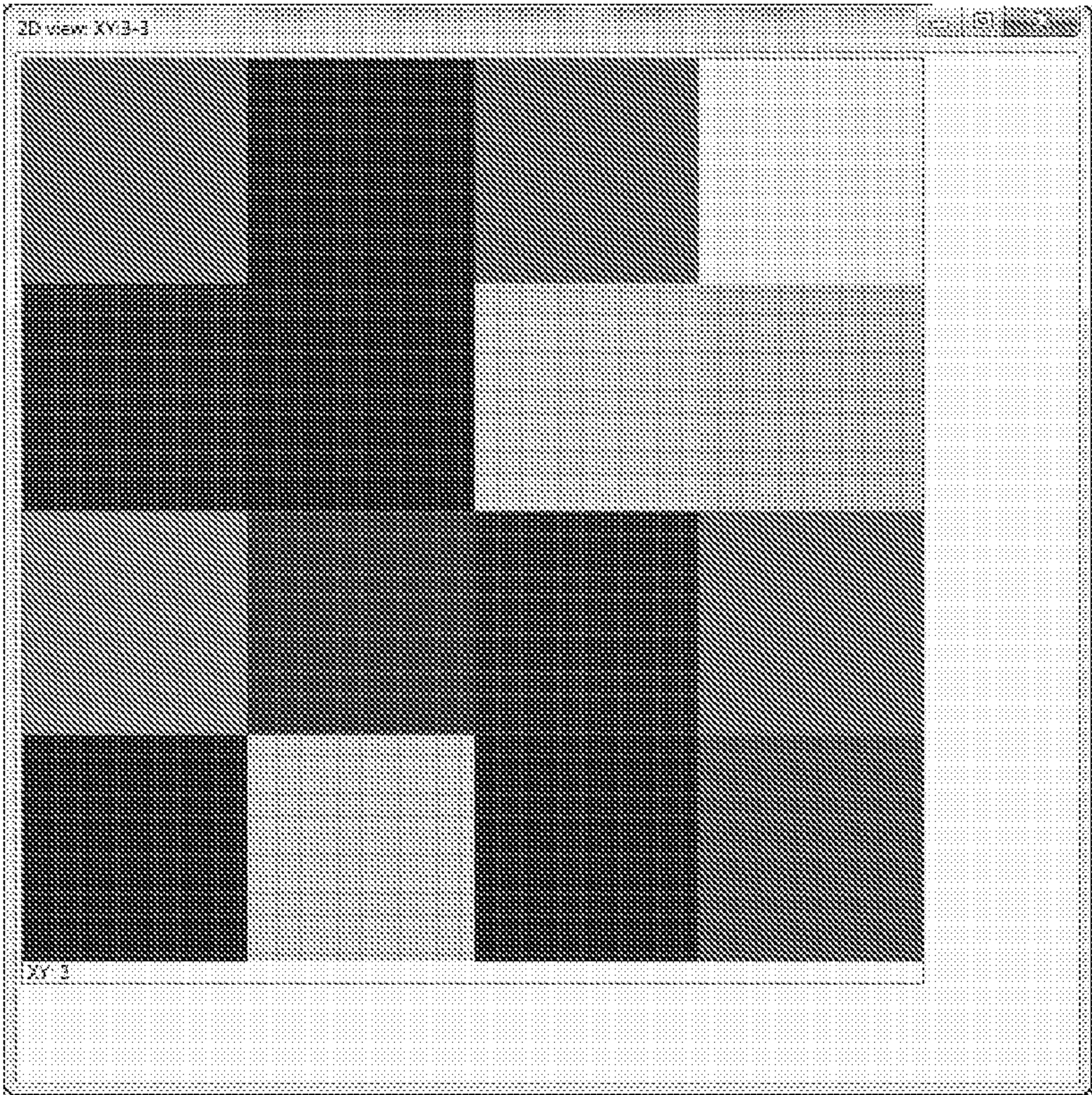


FIG. 9A

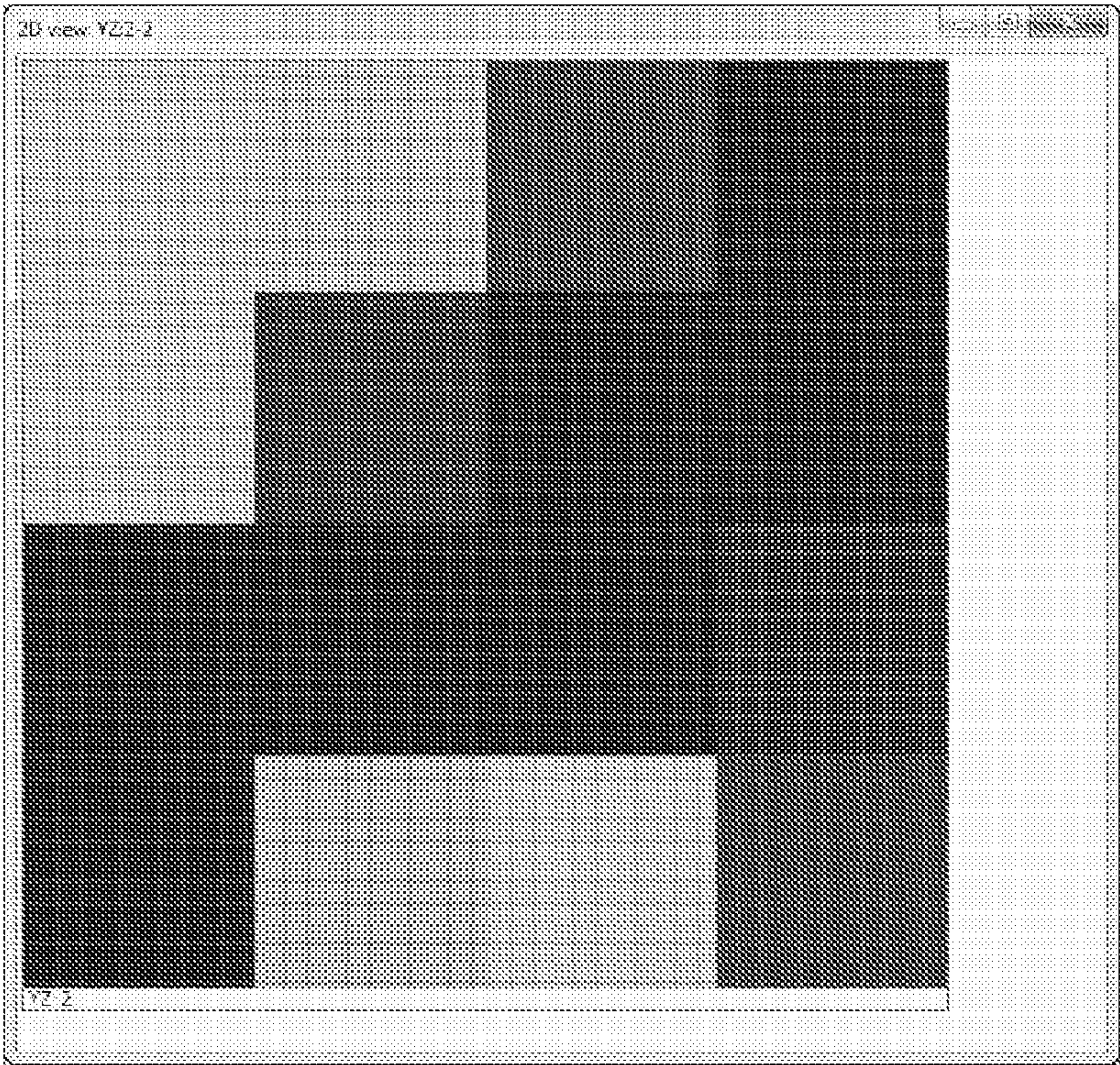


FIG. 9B

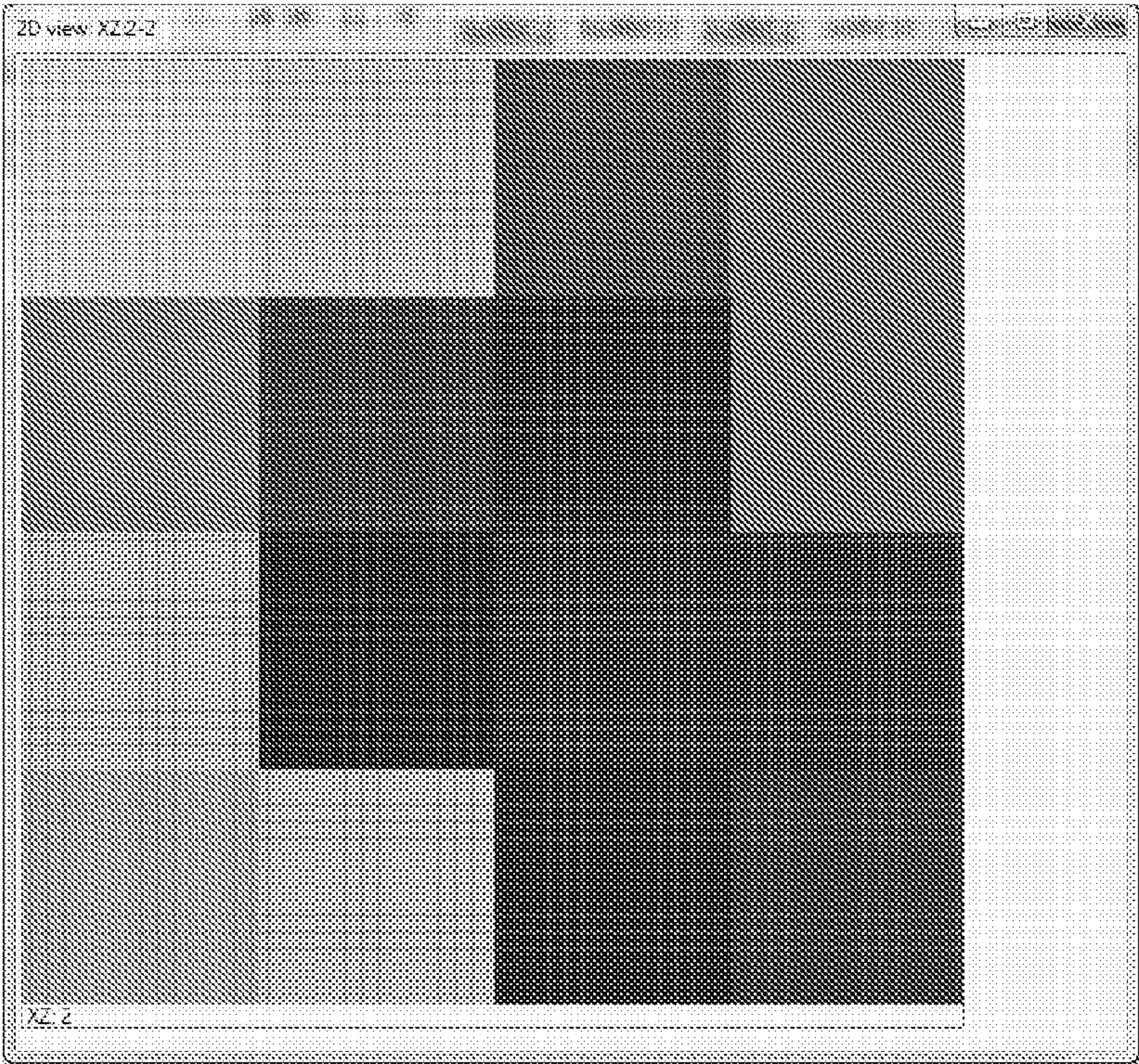


FIG. 9C

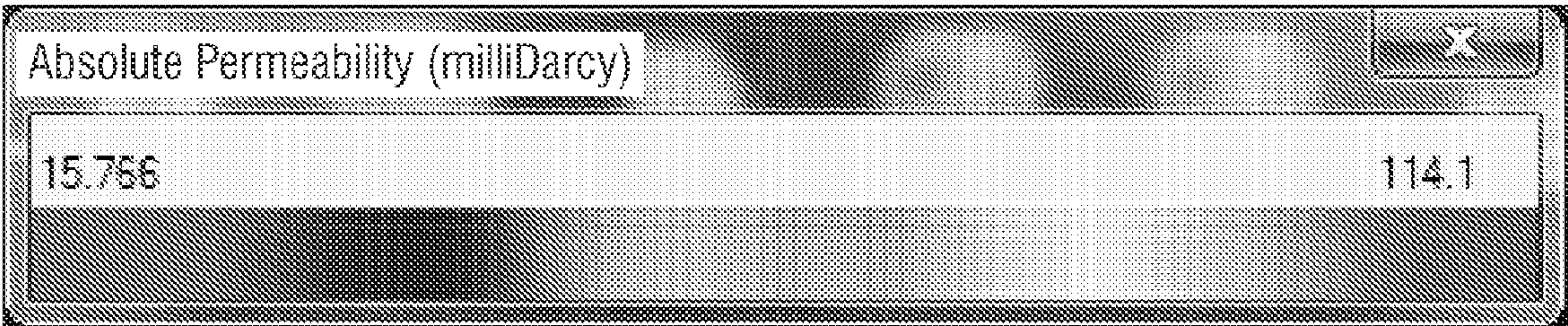


FIG. 10

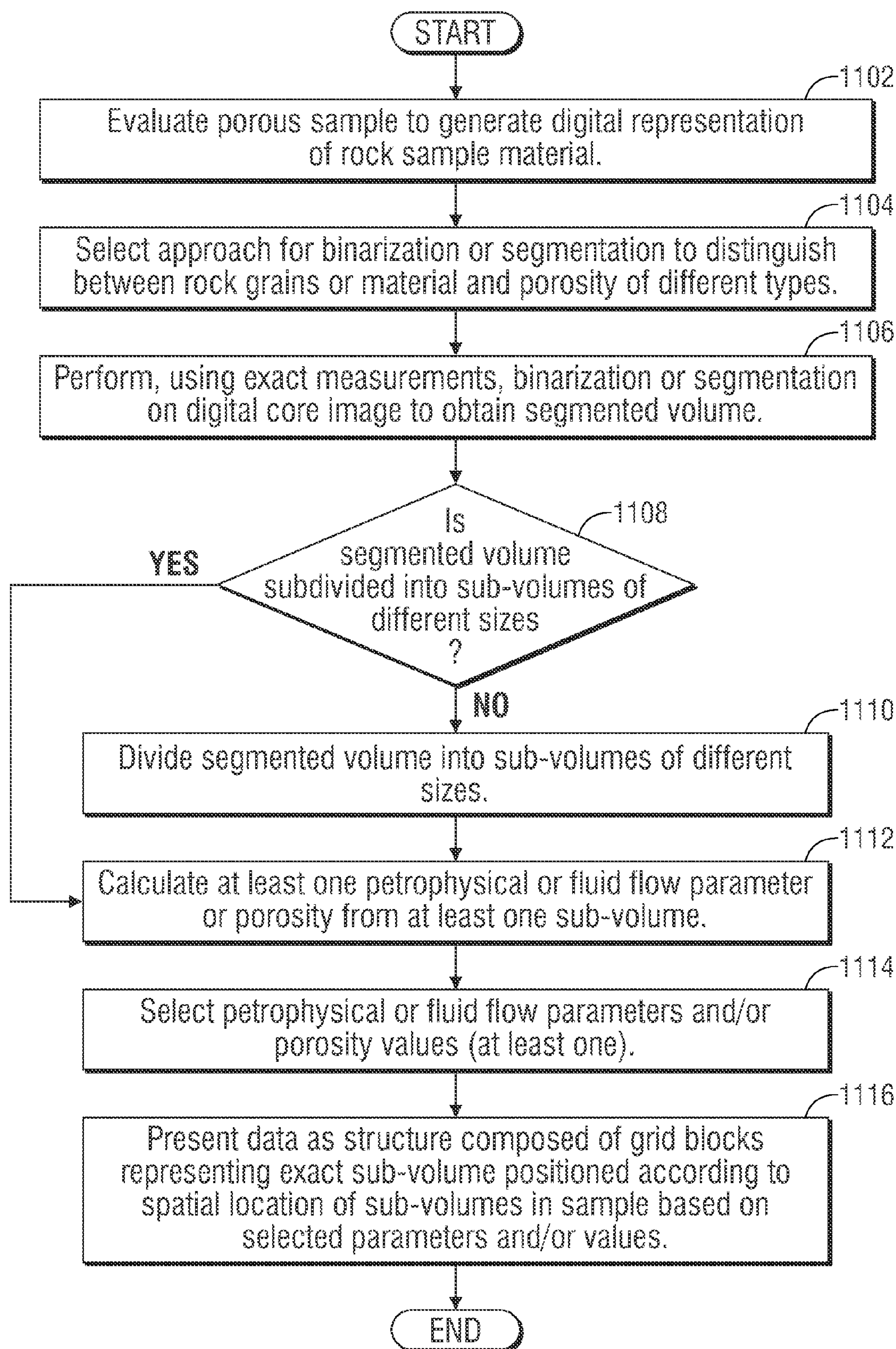


FIG. 11

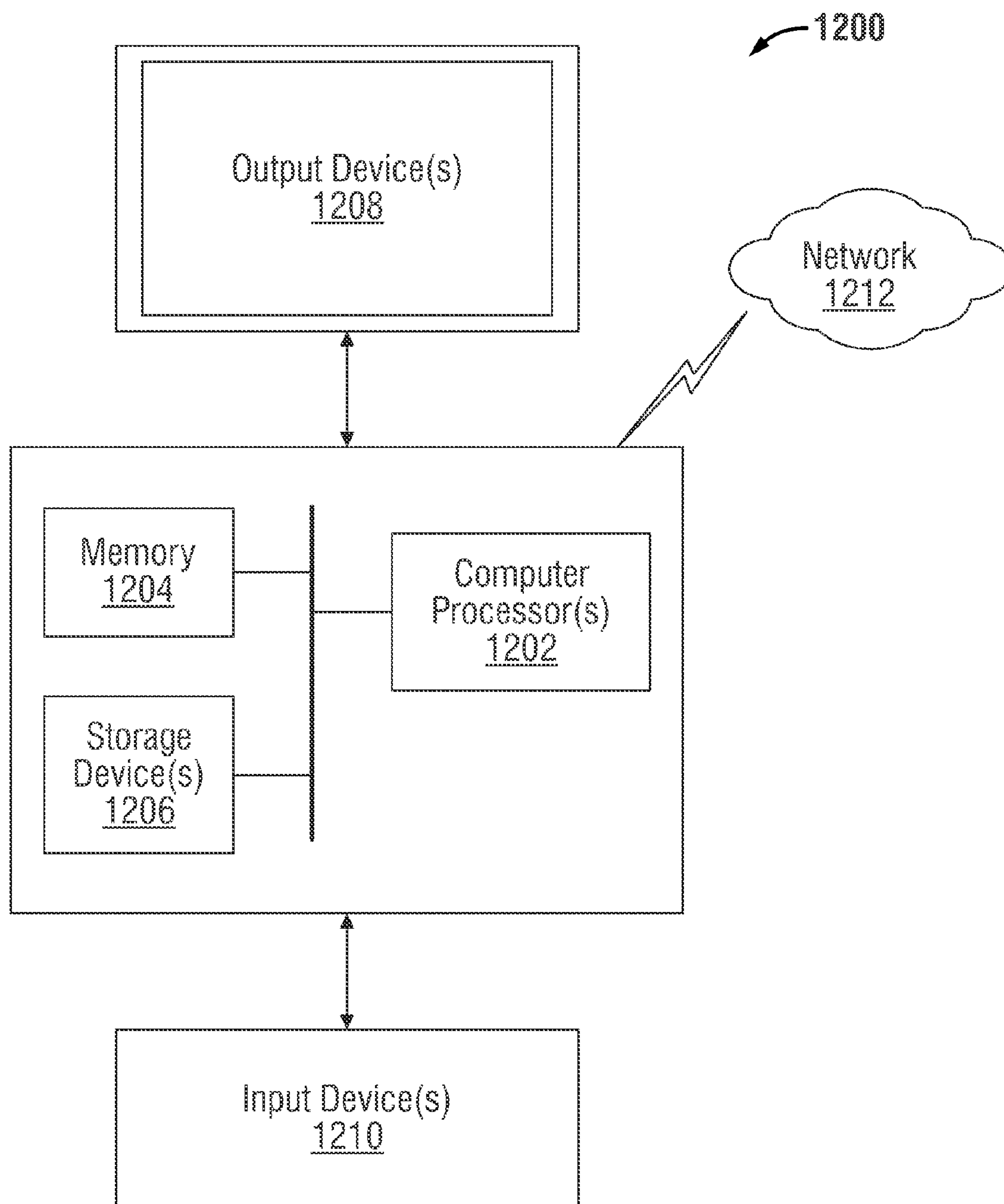


FIG. 12

METHOD AND SYSTEM OF SHOWING HETEROGENEITY OF A POROUS SAMPLE

CROSS-REFERENCE TO RELATED APPLICATION

[0001] This application claims priority from U.S. Provisional Patent Application 61/912,479, filed Dec. 5, 2013, which is incorporated herein by reference.

BACKGROUND

[0002] Operations, such as geophysical surveying, drilling, logging, well completion, and production, are typically performed to locate and gather valuable downhole fluids. Surveys are often performed using acquisition methodologies, such as seismic mapping, resistivity mapping, etc., to generate images of underground formations. These formations are often analyzed to determine the presence of subterranean assets, such as valuable fluids or minerals, or to determine if the formations have characteristics suitable for storing fluids. Although the subterranean assets are not limited to hydrocarbons such as oil, throughout this document, the terms “oilfield” and “oilfield operation” may be used interchangeably with the terms “field” and “field operation” to refer to a site where any types of valuable fluids or minerals can be found and to the activities required to extract them. The terms may also refer to sites where substances are deposited or stored by injecting them into the earth using boreholes and the operations associated with this process. Further, the term “field operation” refers to a field operation associated with a field, including activities related to field planning, wellbore drilling, wellbore completion, and/or production using the wellbore.

[0003] Simulations are commonly used in the oil industry and other industries to model processes and predict behaviors. Each type of simulation is relevant to a certain scale of process. A common example in the oil industry is the use of reservoir flow models to predict dynamic behavior at the scale of a reservoir, which can be from a few meters to hundreds of meters thick and can be thousands of meters in lateral extent. The volume elements in these models are typically on the order of meters or tens of meters on a side. Reservoir scale processes, such as developed miscibility, can develop within the model.

[0004] At the other extreme, micromodels of porous media represent small pieces of the media, typically with volume elements on the order of a few microns or less on a side and full models that are on the order of millimeters or less in extent. In these models, the small size means the residence time of fluids within the model is too short for many processes to develop fully. The present disclosure is within the domain of these small models.

[0005] Static micromodels representing pore and grain geometry can be obtained in several ways at different scales. Thin sections of rocks are formed by injecting a colored epoxy into a rock and then slicing an optically thin section and mounting it onto a glass slide. The thin section is then optically analyzed to obtain images of the pores and grains. Multiple thin sections can be used to create a micromodel, typically using statistical distributions rather than making an image directly from stacked thin sections. Alternatively, a small rock volume can be scanned using X-rays in a micro computed tomography (microCT) machine. The tomographic inversion of the X-ray scans is used to create a static

model of a rock with resolution ranging from tens of microns to tens of nanometers. This CT image is processed and segmented into grains and pores. A third method uses ion beam milling and scanning electron microscopy to create a series of images with nanometer-scale resolution. These images can be analyzed and used to construct a static three-dimensional (3D) model of a tiny portion of the rock.

[0006] Micromodels for flow-dynamic behavior in porous media are of a few types. Pore network models substitute a complex network of nodes and connectors to represent the pores and pore throats, respectively. The network is based on a static representation rock model, and flow dynamics are applied to the pore network. Lattice Boltzmann models are based on movement of particles on a 3D grid, which can be placed within a static rock model. A third method uses microhydrodynamical modeling in a static rock model to represent simple or complex fluid-fluid and fluid-rock interactions during flow or while a chemical process develops.

[0007] Subsample data analysis is a known procedure in the core analysis domain. U.S. Pat. No. 8,155,377 describes a method to determine rock physics relationships (based on statistical best fit analysis) using CT images by plotting the porosity and modeled petrophysical parameter followed by an estimation of the correlation between them. As this patent does not utilize the spatial information for the sub-sample data analysis it cannot be directly applied for the analysis of the spatial heterogeneity of the sample. Further, U.S. Pat. No. 8,081,802 describes a method to determine the permeability of the rock formation using the CT images and includes binarization segmentation of the CT images, selection of the sub-volumes, and determination of the permeability tensor and its principal values and directions. U.S. Pat. No. 8,081,802 is focused on the sample permeability estimation. It does not provide any spatial correlation for the sample properties.

BRIEF DESCRIPTION OF THE DRAWINGS

[0008] The appended drawings illustrate several embodiments of a graphical representation of a method and system of showing heterogeneity of a porous sample and are not to be considered limiting of its scope.

[0009] FIG. 1 is a schematic view, partially in cross-section, of a field in which one or more embodiments of a method and system of showing heterogeneity of a porous sample may be implemented.

[0010] FIGS. 2 and 3 depict schematic diagrams in accordance with one or more embodiments of a method and system of showing heterogeneity of a porous sample.

[0011] FIG. 4 is a 3D representation of a sub-sample property, in this case absolute permeability in the X direction.

[0012] FIG. 5A is a 3D representation of the sub-sample property of FIG. 4 in the X direction wherein grid blocks with absolute permeability of less than 53.16 milliDarcy are transparent.

[0013] FIG. 5B is a 3D representation of the sub-sample property of FIG. 4 in the Y direction wherein grid blocks with absolute permeability of less than 53.16 milliDarcy are transparent.

[0014] FIG. 5C is a 3D representation of the sub-sample property of FIG. 4 in the Z direction wherein grid blocks with absolute permeability of less than 53.16 milliDarcy are transparent.

[0015] FIG. 6 is a 3D representation of a sub-sample property, in this case porosity, wherein grid blocks with a porosity fraction less than 0.182 are transparent.

[0016] FIG. 7 is a 3D representation of a sample property with at least one highlighted scalar value of the property.

[0017] FIG. 8 is the 3D representation of the porosity distribution of FIG. 6 with the permeability values of the cubes in the X, Y, and Z directions included graphically in the form of arrows.

[0018] FIG. 9A is the 2D XY section of the 3D cube identified in FIG. 5C.

[0019] FIG. 9B is the 2D YZ section of the 3D cube identified in FIG. 5C.

[0020] FIG. 9C is the 2D XZ section of the 3D cube identified in FIG. 5C.

[0021] FIG. 10 is the color palette for the 2D sections of FIGS. 9A-9C.

[0022] FIG. 11 is a flowchart of a method of showing heterogeneity of a porous sample.

[0023] FIG. 12 is a computer system on which one or more embodiments of a method and system of showing heterogeneity of a porous sample may be implemented.

DETAILED DESCRIPTION

[0024] Aspects of the present disclosure are shown in the above-identified drawings and described below. In the description, like or identical reference numerals are used to identify common or similar elements. The drawings are not necessarily to scale and certain features may be shown exaggerated in scale or in schematic in the interest of clarity and conciseness.

[0025] The term “digital rock model”, as used in this application, refers to pore and grain level models of a porous medium. The resolution of these models is typically in the range of a few microns or less. The digital rock model is generated based on a 3D porous solid image of a core sample. A 3D porous solid image is a 3D digital representation of the core sample that is generated using computed tomography, scanning electron microscopy, focused ion beam scanning electron microscopy, confocal microscopy, or other suitable methods of core imaging. Specifically, the 3D porous solid image is an image of each portion of the core sample including pores and solid surfaces. Thus, the 3D porous solid image may show pores and rock boundaries of the core sample for each layer of the core sample. While the 3D porous solid image may show the physical structure of the core sample, the digital rock model can be based on binary or segmented color or greyscale images. Image binarization is a segmentation into two “phases” (e.g. two colors) such that the first “phase” is a phase in question, and the second phase is a combination of all other phases. A rock model may include the lithology of the core sample. For example, the lithographic properties of the core sample may include pore size distribution, rock type, or tortuosity measurements. Fluid flow processes may be simulated in a digital rock model using various techniques. These flow processes represent subterranean fluids that are native to a rock formation or injected into the rock formation.

[0026] The term “core sample”, as used in this application, refers to a two dimensional or three dimensional porous medium representing a geological region. For example, the geological region may correspond to a portion of an oilfield. In particular, a core sample refers to a physical sample obtained from the geological region. For example, the core

sample may be obtained by drilling into the portion of the oilfield with a core drill to extract the core sample from the portion. The core sample may contain subterranean fluids, such as multiphase compositional fluids. In particular, the subterranean fluids may include liquids, gases, injectants, or combinations thereof.

[0027] In order to perform mathematical modeling, explicit values or analytical expressions that are dependent on local temperature and local molar densities may be used for the following quantities: bulk and surface Helmholtz energy or entropy, density, volume, and shear viscosity (or other rheological properties including effects like adsorption, elongational viscosity, viscoelasticity, size exclusion effect, etc.), thermal and diffusion transport coefficients, surface tension at the contact between fluid and rock and between different fluids. In one or more embodiments mathematical modeling includes generation of a digital fluid model of the fluids based on physical properties of individual phases, physical and chemical properties of complex multiphase, multicomponent fluids (including but not limited to any combination of the following: bulk and surface thermodynamics, diffusion, kinetics, and rheology). For these quantities, experimental values or experimentally validated correlations with respect to temperature and molar densities are used in one or more embodiments. In one or more embodiments laboratory fluid data describes physical properties of individual phases, including but not limited to density and viscosity, compositional properties, and multiphase phenomena. In one or more embodiments compositional and multiphase phenomena includes but are not limited to any combination of the following:

[0028] bulk thermodynamics (bulk equilibrium data including, but not limited to, compressibility values, equilibrium constants for phase transitions and/or chemical reactions, and heat capacities);

[0029] surface thermodynamics (surface equilibrium data concerning gas-liquid, liquid-liquid, or gas/liquid-solid interactions. This includes but is not limited to interfacial tension coefficients, adsorption isotherms, wetting angles, capillary pressure, etc.);

[0030] diffusion (diffusion rates and cross-influence in diffusion of different components);

[0031] kinetics (type of the kinetic model and explicit values of kinetic coefficients describing chemical reaction rates);

[0032] rheology (rheological model type and values of rheological parameters).

[0033] In order to obtain material parameters experimentally, standard and well-established laboratory methods are used such as mass density obtained by buoyancy or acoustic principles. Shear viscosity obtained from the drag force of a fluid moving past a surface also depends on shear rate (shear rheology). Advanced rheological characterization of non-Newtonian reservoir and fluids for example, can be obtained by means of rotary viscometers, core flooding, measurements of adsorption, or flooding within channels of controlled geometry. Pendant drop tensiometers and drop shape analysis can be used to determine the interfacial tension and contact angle between fluid/fluid and fluid/fluid/solid.

[0034] FIG. 1 depicts a schematic view, partially in cross section, of an oilfield 100 in which one or more embodiments of user-sourced data issue management may be implemented. 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 of user-sourced data issue management should not be considered limited to the specific arrangements of modules shown in FIG. 1.

[0035] As shown in FIG. 1, the subterranean formation 104 includes several geological structures (106-1 through 106-4). As shown, the formation includes 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 extends 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. As noted above, the outputs of these various survey tools and/or data acquisition tools, as well as data derived from analyzing the outputs, are considered as part of the historic information.

[0036] Further, as shown in FIG. 1, the wellsite system 110 is associated with a rig 101, a wellbore 103, and other downhole equipment 109 and is configured to perform wellbore operations, such as logging, drilling, fracturing, production, or other applicable operations. The wellbore 103 reaches the reservoir 106-5, which is where valuable fluids such as hydrocarbons, minerals, and water are typically found. Generally, survey operations and wellbore operations are referred to as oilfield operations of the oilfield 100. These oilfield operations may be performed as directed by the surface unit 112.

[0037] In one or more embodiments, the surface unit 112 is operatively coupled to a digital core modeling system 116 and/or a wellsite system 110. In particular, the surface unit 112 is configured to communicate with the digital core modeling system 116 and/or the wellsite system 110 to send commands to the digital core modeling system 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 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 digital core modeling system 116, the wellsite system 110, or other parts of the oilfield 100. The surface unit 112 may also be provided with functionality for actuating mechanisms at the oilfield 100. The surface unit 112 may then send command signals to the oilfield 100 in response to data received, for example to control and/or optimize various oilfield operations described above.

[0038] In one or more embodiments, the data received by the surface unit 112 represents characteristics of the subterranean formation 104 and may include seismic data and/or information related to porosity, saturation, permeability, natural fractures, stress magnitude and orientations, elastic properties, etc. during a drilling, fracturing, logging, or production operation of the wellbore 103 at the wellsite system 110.

[0039] In one or more embodiments, the surface unit 112 is communicatively coupled to the digital core modeling system 116. Generally, the digital core modeling system 116 is configured to analyze, model, control, optimize, or perform other management tasks of the aforementioned oilfield operations based on the data provided from the surface unit 112. Although the surface unit 112 is shown as separate from the digital core modeling system 116 in FIG. 1, in other

examples, the surface unit 112 and the digital core modeling system 116 may be combined.

[0040] FIG. 2 shows a schematic view of a portion of the oilfield 120 of FIG. 1, depicting a producing wellsite 122 and surface network 124 in detail. The wellsite 122 of FIG. 2 includes a wellbore 126 extending into the earth therebelow. In addition, FIG. 2 shows an injection wellsite 128 having an injection wellbore 130. As shown, the wellbores 126 and 130 have already been drilled, completed, and prepared for production from reservoir 132.

[0041] Wellbore production equipment 134 extends from a wellhead 136 of wellsite 122 and to the reservoir 132 to draw fluid to the surface. The wellsite 122 is operatively connected to the surface network 124 via a transport line 138. Fluid flows from the reservoir 132, through the wellbore 126, and into the surface network 124. The fluid then flows from the surface network 124 to the process facilities 140.

[0042] As described above, fluid may be injected through an injection wellbore, such as the wellbore 130 to gain additional amounts of hydrocarbon. Fluid may be injected to sweep hydrocarbons to producing wells and/or to maintain reservoir pressure by balancing extracted hydrocarbons with injected fluid. The wellbore 130 may be a new well drilled specifically to serve as an injection wellbore, or an already existing well that is no longer producing hydrocarbons economically. As shown in FIG. 2, wellbore injection equipment 142 extends from a wellhead 144 of injection wellsite 128 to inject fluid (e.g., shown as 146 and 148 in FIG. 2) in or around the periphery of the reservoir 132 to push hydrocarbons (e.g., shown as 150 in FIG. 2) toward a producing wellbore, such as the wellbore 126. The injection wellsite 128 is operatively connected to an injection transport line 152, which provides the injection fluid to the injection wellsite 128 through the wellhead 144 and down through the well injection equipment 142.

[0043] As further shown in FIG. 2, sensors S are located about the oilfield 120 to monitor various parameters during oilfield operations. The sensors S may measure, for example, pressure, temperature, flow rate, composition, and other parameters of the reservoir, wellbore, surface network, process facilities and/or other portions of the oilfield operation. The sensors S are operatively connected to a surface unit 154 for collecting data therefrom. The surface unit may be, for example, similar to the surface unit 112 of FIG. 1.

[0044] One or more surface units 154 may be located at the oilfield 120, or linked remotely thereto. The surface unit 154 may be a single unit, or a complex network of units used to perform the modeling, planning, and/or management functions throughout the oilfield 120. The surface unit 154 may be a manual or automatic system. The surface unit 154 may be operated and/or adjusted by a user. The surface unit 154 is adapted to receive and store data. The surface unit 154 may also be equipped to communicate with various oilfield equipment. The surface unit 154 may then send command signals to the oilfield in response to data received or modeling performed.

[0045] As shown in FIG. 2, the surface unit 154 has computer facilities, such as memory 156, a controller 158, a processor 160, and a display unit 162, for managing the data. The data is collected in memory 156, and processed by the processor 160 for analysis. Data may be collected from the oilfield sensors S and/or by other sources. For example,

oilfield data may be supplemented by historical data collected from other operations, or user inputs.

[0046] The analyzed data (e.g., based on modeling performed) may then be used to make decisions. A transceiver may be provided to allow communications between the surface unit **154** and the oilfield **120**. The controller **158** may be used to actuate mechanisms in the oilfield **120** via the transceiver and based on these decisions. In this manner, the oilfield **120** may be selectively adjusted based on the data collected. These adjustments may be made automatically based on computer protocol and/or manually by an operator. In some cases, well plans are adjusted to select optimum operating conditions or to avoid problems.

[0047] To facilitate the processing and analysis of data, simulators may be used to process the data for modeling various aspects of the oilfield operation. Specific simulators are often used in connection with specific oilfield operations, such as reservoir or wellbore simulation. 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.

[0048] As shown, the oilfield operation is provided with wellsite and non-wellsite simulators. The wellsite simulators may include a reservoir simulator **163**, a wellbore simulator **164**, and a surface network simulator **166**. The reservoir simulator **163** solves for hydrocarbon flow through the reservoir rock and into the wellbores. The wellbore simulator **164** and surface network simulator **166** solves for hydrocarbon flow through the wellbore and the surface network **124** of pipelines. As shown, some of the simulators may be separate or combined, depending on the available systems.

[0049] The non-wellsite simulators may include process **168** and economics **170** simulators. The process simulator **168** models the processing plant (e.g., the process facilities **140**) where the hydrocarbon(s) is/are separated into its constituent components (e.g., methane, ethane, propane, etc.) and prepared for sale. The oilfield **120** is provided with an economics simulator **170**. The economics simulator **170** models the costs of part or the entire oilfield **120** throughout a portion or the entire duration of the oilfield operation. Various combinations of these and other oilfield simulators may be provided.

[0050] FIG. 3 shows a schematic diagram of the digital core modeling system **172** that accepts as input a core sample **186** in accordance with one or more embodiments. As discussed above, the digital core modeling system **172** may include at least a portion of the surface unit shown and described in relation to FIG. 1 and FIG. 2. The digital core modeling system **172** includes a computing system **174** and measurement and testing equipment **184**.

[0051] In one or more embodiments, the computing system **174** includes a digital core modeling tool **176**, a simulation tool **188**, a display **180** and a data repository **190**. Each of these components is described below.

[0052] In one or more embodiments, the digital core modeling tool **176** is a tool for performing digital core modeling for the oilfield. The digital core modeling tool **176** may include hardware, software, or a combination of both. For example, the hardware may include a computer processor and memory.

[0053] The measurement and testing equipment **184** includes such tools as a core sample scanner configured to

generate a digital core image **178** from a core sample **186**. A digital core image **178** is a two-dimensional (2D) or 3D digital representation of the core sample **186**. Specifically, the digital core image **178** is an image of each portion of the core sample **186** including pores and solid surfaces. Thus, the digital core image **178** may show pores and rock boundaries of the core sample for each layer of the core sample **186**. The digital core image **178** may also include data that can be used to determine relationships (such as a relationship between the porosity and a modeled petrophysical parameter) without using statistical analysis, such as a statistical best fit. In accordance with one or more embodiments, the core sample scanner may scan the core sample **186** with or without destroying the core sample **186** in the process. In one or more embodiments, the software of the digital core modeling tool **176** may include an interface, a digital core model generator, an image generator, and a simulation tool **188**. The simulation tool **188** may use the Density Functional (DF) method for complex pore-scale hydrodynamics. The simulation tool **188** includes functionality to perform simulations on a digital core model **182**. Specifically, the simulations simulate various scenarios on the core sample **186**. The purpose of the simulations is to identify additional properties of the core sample **186**, to validate the digital core model **182**, to identify how the core sample **186** may be affected by the example scenarios, to extrapolate the simulation results to identify how the field (e.g., oilfield or other geographic region) may be affected by performing the example scenario in the field, or to perform another task or combination thereof. The simulation tool **188** may include various input parameters describing an example scenario and generate a simulation result for the example scenario.

[0054] The software components may execute on the computer processor and use the memory.

[0055] Continuing with FIG. 3, the interface may include a user interface and/or an application programming interface (API). The interface includes functionality to receive input and transmit output, such as to the display **180**. For example, the input may be the digital core image **178** of one or more core samples and other information. The output may correspond to graphical representation of simulation results or for display on the display **180**, commands to send to the wellsite for controlling production, and other output. In one or more embodiments, the display **180** is configured to display graphical representations showing heterogeneity of a porous rock sample and models.

[0056] The digital core model generator corresponds to software that includes functionality to generate a digital core model **182** from the digital core image **178**. A digital core model **182** describes the core sample **186**. Specifically, whereas the digital core image **178** may show the physical structure of the core sample **186**, the digital core model **182** may include the lithology of the core sample **186**. For example, the lithographic properties of the core sample **186** may include pore size distribution, rock type, tortuosity measurements, statistical results generated from the properties, and other information.

[0057] In one or more embodiments, the image generator includes functionality to generate 2D and/or 3D images from the simulation results, which may be stored or displayed. Further, relationships between the porosity and modeled petrophysical parameters using estimated porosity and the modeled petrophysical parameter from sub-volumes may be

stored or displayed. However, in accordance with one or more embodiments, these relationships are determined using the entire digital core model **182** and not by using statistical analysis, such as statistical best fit. Accordingly, in one or more embodiments, no relationship determined by a statistical analysis (such as statistical best fit) and the modeled petrophysical parameter is stored or displayed.

[0058] Continuing with FIG. **3**, the various components of the digital core modeling tool **176** may include functionality to store and retrieve data from the data repository **190**. In one or more embodiments, the data repository **190** 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 **190** 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. As shown in FIG. **3**, the data repository **190** includes functionality to store one or more digital core images **178**, one or more digital core models **182**, and simulation results.

[0059] As discussed above, the digital core images **178** are 3D images of core samples **186** in accordance with one or more disclosed embodiments. Further, the digital core models **182** are models of the core sample **186**. For example, if multiple core samples are used, each core sample may have a unique associated digital core image of the core sample and a unique associated digital core model of the core sample.

[0060] As further discussed above, relationships between the porosity and modeled petrophysical parameters using estimated porosity and the modeled petrophysical parameter from sub-volumes may be stored in the data repository **190**. However, in accordance with one or more embodiments, these relationships are determined using the entire digital core model **182** and not by using statistical analysis, such as statistical best fit. Accordingly, in one or more disclosed embodiments, no relationship determined by a statistical analysis (such as statistical best fit) and the modeled petrophysical parameter is stored in the data repository **190**. In one or more embodiments, the simulation results are results of performing one or more simulations.

[0061] While FIGS. **1-3** show a configuration of components, other configurations may be used without departing from the scope of embodiments. For example, various components may be combined to create a single component. As another example, the functionality performed by a single component may be performed by two or more components.

[0062] Disclosed is a method of displaying and analyzing sample heterogeneity which includes evaluating a rock or other porous material using computed tomography, scanning electron microscopy, focused ion beam scanning electron microscopy, confocal microscopy, or other techniques that result in either a 2D or a 3D digital representation of the rock sample material followed by a binarization or segmentation process to distinguish between the rock grains or material and porosity of different types (at least one). The volume is then divided into the sub-volumes of different sizes. At least one petrophysical or fluid flow parameter or porosity is calculated from at least one sub-volume. The data are presented in the form of a 2D or 3D structure composed of the grid blocks representing the exact sub-volume positioned according to the spatial location of the sub-volumes in the sample using the particular coloring scheme and/or different shapes (including but not limited with arrows, line segments,

etc.) which depends on the selected petrophysical or fluid flow parameters and/or porosity values (at least one). No statistical analysis (including a statistical best fit analysis) is used to determine any relationships between the parameter (s) and/or value(s) as part of the disclosed embodiments.

[0063] These values represent at least one of the following parameters: porosity, petrophysical property, fluid flow parameter, Routine Core Analysis (RCA), or Special Core Analysis Laboratory (SCAL) experimental or simulation data.

[0064] The simulated subsample properties may include fluid flow, electrical resistivity, geomechanical properties, sample porosity, among others, or any combination thereof. The transparency levels and the cutoffs can be applied to the data representation to analyze distribution of the selected petrophysical or fluid flow properties within the 2D or 3D space. In one of the embodiments, the data type of representation can be used for the heterogeneity analysis of the rock sample.

[0065] In one of the embodiments this method can be used to generate an upscaled model of the digital rock sample with the 2D or 3D relationship between physical properties of the sample and their spatial distribution. Representations can also include links to any scalar data, 2D distributions, reports, etc. Further, experimental and simulation data can be linked using the representation of different properties, such as values that represent at least one of the following parameters: porosity, petrophysical property, fluid flow parameter, RCA, or SCAL experimental or simulation data. Using this ability, the data coming from different sources may be cross-correlated together with the spatial information.

[0066] Different examples of data representation can include (but are not limited to) those illustrated as follows:

[0067] FIG. **4** is a 3D representation of the sub-sample property with a particular coloring scheme (example shows absolute permeability value in the X direction in milliDarcy (mD)).

[0068] FIGS. **5A-5C** are, respectively, a 3D representation of the sub-sample properties, in this particular example X, Y, Z directional absolute permeability distribution within the sample is shown and the transparency scheme is applied (grid blocks with permeability less than 53.16 mD are transparent).

[0069] FIG. **6** is a 3D representation of the sub-sample properties, in this particular example porosity (fraction) distribution within the sample is shown and the transparency scheme is applied (grid blocks with porosity less than 0.182 are transparent).

[0070] FIG. **7** is a 3D representation of a sample property with at least one highlighted scalar value of the property.

[0071] FIG. **8** is a 3D representation of the porosity distribution within the sample with the added information on permeability values of the cubes in X, Y, and Z directions included graphically in the form of arrows.

[0072] FIG. **9A** is the 2D XY section of the 3D cube of FIG. **5C**.

[0073] FIG. **9B** is the 2D YZ section of the 3D cube of FIG. **5C**.

[0074] FIG. **9C** is the 2D XZ section of the 3D cube of FIG. **5C**.

[0075] FIG. **10** is the color palette for the 2D sections of FIGS. **9A-9C**. Different palettes for the different properties (shades of grey for the porosity, color scheme for the

permeability) can also be applied. Textures or other graphical attributes can also be assigned to distinguish features or ranges of features.

[0076] FIG. 11 depicts an example method for showing heterogeneity of a porous sample. In one or more embodiments, one or more of the elements shown in FIG. 11 may be omitted, repeated, or performed in a different order. Accordingly, embodiments of the invention should not be considered limited to the specific arrangements of elements shown in FIG. 11.

[0077] Initially, in block 1102, a rock or other porous material is evaluated using computed tomography, scanning electron microscopy, focused ion beam scanning electron microscopy, confocal microscopy, or other techniques that result in either a 2D or a 3D digital representation of the rock sample material. Next, in block 1104, an approach for binarization or segmentation is selected to distinguish between the rock grains or material and porosity of different types (at least one).

[0078] In block 1106, the binarization or segmentation is performed using exact measurements to distinguish between the rock grains or material and porosity of different types (at least one) to obtain a segmented volume. In block 1108, a determination is made regarding whether a segmented volume is subdivided into sub-volumes of different sizes. If not, the segmented volume is divided into the sub-volumes of different sizes in block 1110. If so, there is no need to sub-divide the volume and the process proceeds to block 1112.

[0079] In block 1112, at least one petrophysical or fluid flow parameter or porosity is calculated from at least one sub-volume. Next, at least one petrophysical or fluid flow parameter or porosity is selected (block 1114).

[0080] Finally, in block 1116, data are presented in the form of a 2D or 3D structure composed of the grid blocks representing the exact sub-volume positioned according to the spatial location of the sub-volumes in the sample using the particular color scheme, texture scheme, or different shapes (including but not limited to arrows, line segments, etc.), or a combination of these elements, which depends on the selected petrophysical or fluid flow parameters or porosity values, or a combination of parameters or values.

[0081] Relationships between selected petrophysical or fluid flow parameters or porosity values may be stored or displayed. However, in accordance with one or more embodiments, these relationships are determined using an entire digital core model and not by using statistical analysis, such as statistical best fit. Accordingly, in one or more embodiments, no relationship determined by a statistical analysis (such as statistical best fit) and the modeled petrophysical parameter is either stored or displayed.

[0082] Embodiments may be implemented on virtually any type of computer regardless of the platform being used. As shown in FIG. 12, the computing system 1200 may be of virtually any type regardless of the platform being used. For example, the computing system 1200 may be one or more mobile devices (e.g., laptop computer, smart phone, personal digital assistant, tablet computer, or other mobile device), desktop computers, servers, blades in a server chassis, or any other type of computing device or devices that includes at least the minimum processing power, memory, and input and output device(s) to perform one or more embodiments of the invention. For example, as shown in FIG. 12, the computing system 1200 may include one or more computer processor

(s) 1202, associated memory 1204 (e.g., random access memory (RAM), cache memory, flash memory, etc.), one or more storage device(s) 1206 (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) 1202 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 1200 may also include one or more input device(s) 1210, such as a touchscreen, keyboard, mouse, microphone, touchpad, electronic pen, or any other type of input device. Further, the computing system 1200 may include one or more output device(s) 1208, 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 1200 may be connected to a network 1212 (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. The input and output device (s) may be locally or remotely (e.g., via the network 1212) connected to the computer processor(s) 1202, memory 1204, and storage device(s) 1206. Many different types of computing systems exist, and the aforementioned input and output device(s) may take other forms.

[0083] Software instructions in the form of computer readable program code to perform one or more embodiments 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 one or more embodiments of digital core model construction.

[0084] Further, one or more elements of the aforementioned computing system 1200 may be located at a remote location and connected to the other elements over a network 1212. Further, embodiments may be implemented on a distributed system having multiple nodes, where each portion of an embodiment may be located on a different node within the distributed system. In one or more embodiments, the node corresponds to a distinct computing device. Alternatively, the node may correspond to a computer processor with associated physical memory. The node may alternatively correspond to a computer processor or micro-core of a computer processor with shared memory and/or resources.

[0085] The systems and methods provided relate to the acquisition of hydrocarbons from an oilfield and specifically a method showing heterogeneity of the porous sample. It will be appreciated that the same systems and methods may be used for performing subsurface operations, such as mining, water retrieval, and acquisition of other underground fluids or other geomaterials from other fields. Further, portions of the systems and methods may be implemented as software, hardware, firmware, or combinations thereof.

[0086] While showing heterogeneity of the porous sample 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 may be devised which do not depart from the scope of showing

heterogeneity of the porous sample as disclosed herein. Accordingly, the scope of showing heterogeneity of the porous sample should be limited only by the attached claims.

What is claimed is:

1. A method for showing heterogeneity of a porous sample comprising:

evaluating the porous sample to generate a digital core image;

performing a plurality of segmentations on the digital core image using a plurality of approaches to obtain a segmented volume;

dividing the segmented volume into at least one sub-volume of differing size;

calculating at least one petrophysical or fluid flow parameter or porosity from the at least one sub-volume; and

presenting data as a structure composed of grid blocks representing an exact representation of the at least one sub-volume positioned according to a spatial location of the at least one sub-volume based on selected parameters or values from the at least one petrophysical or fluid flow parameter or porosity.

2. The method of claim 1, wherein the plurality of segmentations comprise binarizations and the segmented volume comprises a binary volume.

3. The method of claim 1, further comprising storing data of the structure for presentation in a 2D or 3D format.

4. The method of claim 1, wherein evaluating the porous sample is performed using at least one from a group consisting of X-ray scanning, computed tomography scanning, scanning electron microscopy, focused ion beam scanning electron microscopy, and confocal microscopy.

5. A system for showing heterogeneity of a porous sample comprising:

a plurality of measurement and testing equipment configured to evaluate the porous sample to generate a digital core image; and

a computing system comprising:

a data repository configured to store the digital core image,

a digital core modeling tool configured to:

perform a plurality of binarizations or segmentations on the digital core image using a plurality of approaches to obtain a binary or segmented volume;

divide the binary or segmented volume into at least one sub-volume of differing size; and

calculate at least one petrophysical or fluid flow parameter or porosity from the at least one sub-volume, and

a display configured to present data as a structure composed of grid blocks representing an exact representation of the at least one sub-volume positioned according to a spatial location of the at least one sub-volume based on selected parameters or values from the at least one petrophysical or fluid flow parameter or porosity.

6. The system of claim 5, wherein the data repository is further configured to store data of the structure for presentation in a 2D or 3D format.

7. The system of claim 5, wherein the plurality of measurement and testing equipment is further configured to evaluate the porous sample using at least one from a group consisting of X-ray scanning, computed tomography scanning, scanning electron microscopy, focused ion beam scanning electron microscopy, and confocal microscopy.

8. A non-transitory computer readable medium comprising instructions for showing heterogeneity of a porous sample, the instructions when executed by a computer processor comprising functionality for:

evaluating the porous sample to generate a digital core image;

performing a plurality of binarizations or segmentations on the digital core image using a plurality of approaches to obtain a binary or segmented volume;

dividing the binary or segmented volume into at least one sub-volume of differing size;

calculating at least one petrophysical or fluid flow parameter or porosity from the at least one sub-volume; and

presenting data as a structure composed of grid blocks representing an exact representation of the at least one sub-volume positioned according to a spatial location of the at least one sub-volume based on selected parameters or values from the at least one petrophysical or fluid flow parameter or porosity.

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