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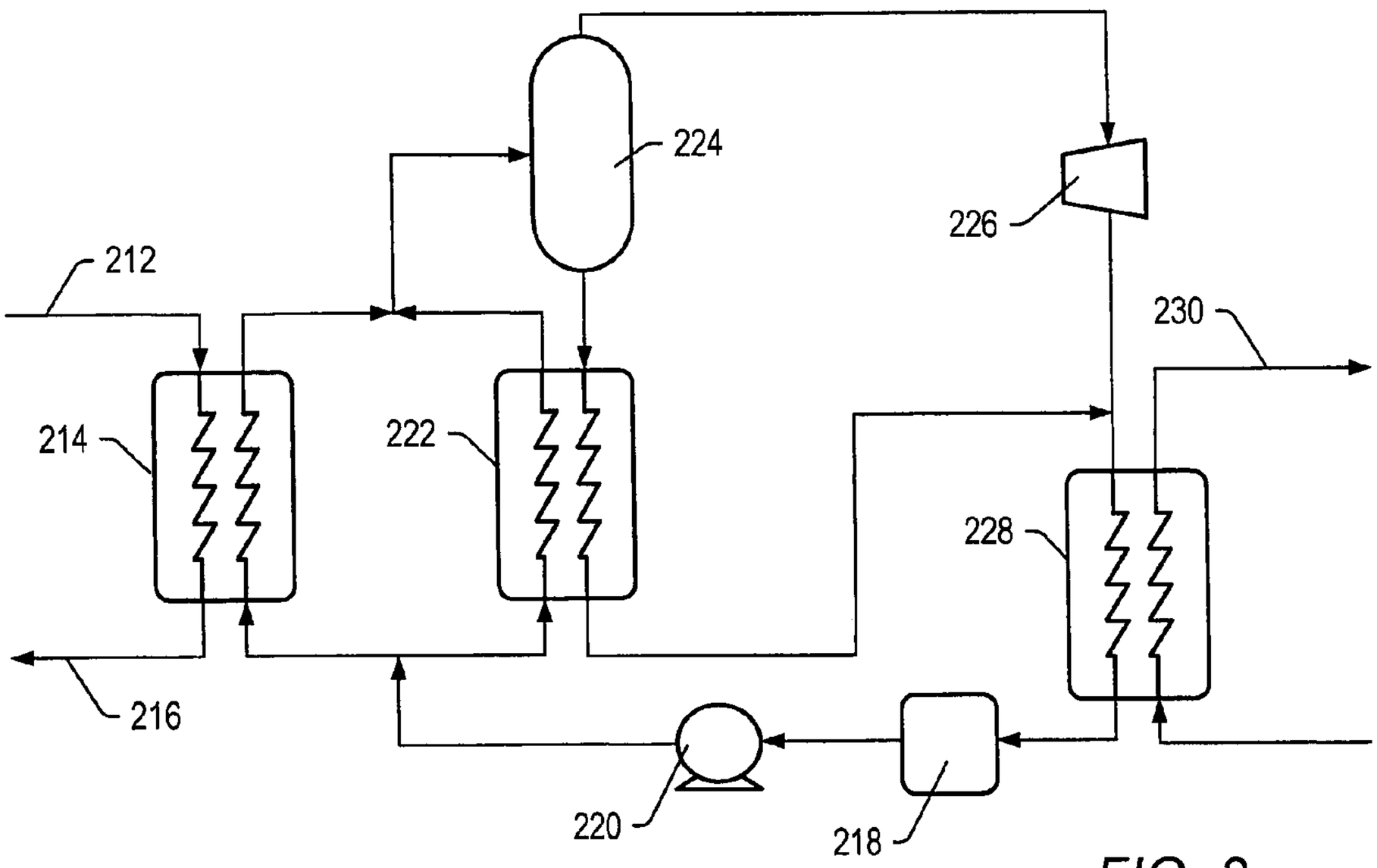


FIG. 3

(57) Abrégé/Abstract:
Systems, methods, and/or heaters for treating subsurface formations are described. Some systems and methods generally relate to heaters and heating systems for subsurface formations. Some systems and methods generally relate to novel components used for these heaters and heating systems. Some systems and methods generally relate to barriers and components associated with barriers used in treating subsurface formations. Some systems and methods generally relate to production wells and novel components for producing fluids from subsurface formations.

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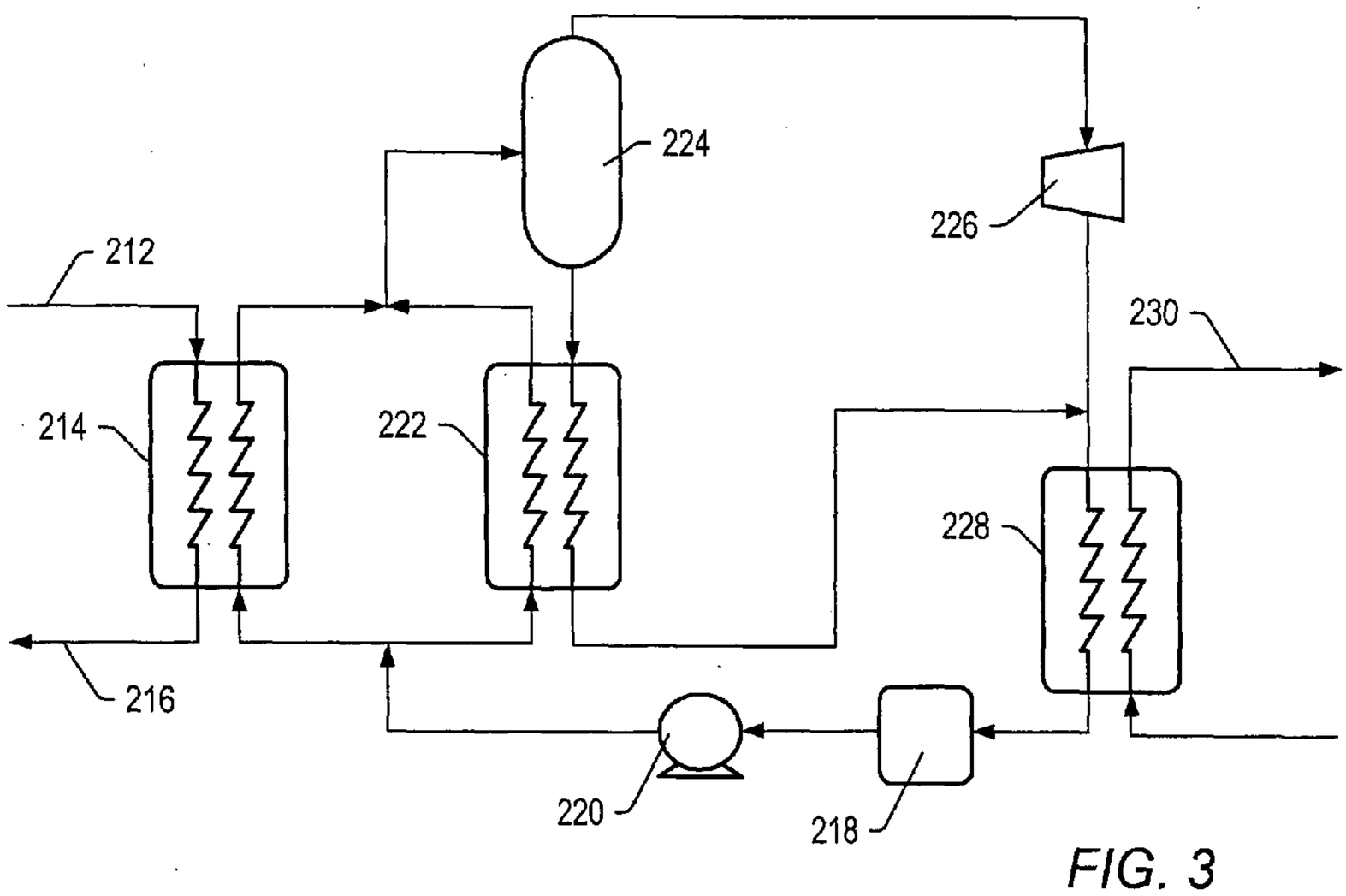


FIG. 3

(57) Abstract: Systems, methods, and/or heaters for treating subsurface formations are described. Some systems and methods generally relate to heaters and heating systems for subsurface formations. Some systems and methods generally relate to novel components used for these heaters and heating systems. Some systems and methods generally relate to barriers and components associated with barriers used in treating subsurface formations. Some systems and methods generally relate to production wells and novel components for producing fluids from subsurface formations.

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SYSTEMS AND PROCESSES FOR USE IN TREATING SUBSURFACE FORMATIONS

BACKGROUND

1. Field of the Invention

[0001] The present invention relates generally to methods and systems for production of hydrocarbons, hydrogen, and/or other products from various subsurface formations such as hydrocarbon containing formations.

2. Description of Related Art

[0002] Hydrocarbons obtained from subterranean formations are often used as energy resources, as feedstocks, and as consumer products. Concerns over depletion of available hydrocarbon resources and concerns over declining overall quality of produced hydrocarbons have led to development of processes for more efficient recovery, processing and/or use of available hydrocarbon resources. In situ processes may be used to remove hydrocarbon materials from subterranean formations. Chemical and/or physical properties of hydrocarbon material in a subterranean formation may need to be changed to allow hydrocarbon material to be more easily removed from the subterranean formation. The chemical and physical changes may include in situ reactions that produce removable fluids, composition changes, solubility changes, density changes, phase changes, and/or viscosity changes of the hydrocarbon material in the formation. A fluid may be, but is not limited to, a gas, a liquid, an emulsion, a slurry, and/or a stream of solid particles that has flow characteristics similar to liquid flow.

[0003] A wellbore may be formed in a formation. In some embodiments wellbores may be formed using reverse circulation drilling methods. Reverse circulation methods are suggested, for example, in published U.S. Patent Application Publication No. 2004-0079553 to Livingstone, and U.S. Patent Nos. 6,854,534 to Livingstone; 6,892,829 to Livingstone, 7,090,018 to Livingstone; and 4,823,890 to Lang. Reverse circulation methods generally involve circulating a drilling fluid to a drilling bit through an annulus between concentric tubulars to the borehole in the vicinity of the drill bit, and then through openings in the drill bit and to the surface through the center of the concentric tubulars, with cuttings from the drilling being carried to the surface with the drilling fluid rising through the center tubular. A wiper or shroud may be provided above the drill bit and above a point where the drilling fluid exits the annulus to prevent the drilling fluid from mixing with formation fluids. The drilling fluids may be, but is not limited to, air, water, brines and/or conventional drilling fluids.

[0004] In some embodiments, a casing or other pipe system may be placed or formed in a wellbore. U.S. Patent No. 4,572,299 issued to Van Egmond et al. describes spooling an electric heater into a well. In some embodiments, components of a piping system may be welded together. Quality of formed wells may be monitored by various techniques. In some

embodiments, quality of welds may be inspected by a hybrid electromagnetic acoustic transmission technique known as EMAT. EMAT is described in U.S. Patent Nos. 5,652,389 to Schaps et al.; 5,760,307 to Latimer et al.; 5,777,229 to Geier et al.; and 6,155,117 to Stevens et al..

[0005] In some embodiments, an expandable tubular may be used in a wellbore. Expandable tubulars are described in U.S. Patent Nos. 5,366,012 to Lohbeck, and 6,354,373 to Vercaemer et al.

[0006] Heaters may be placed in wellbores to heat a formation during an in situ process. Examples of in situ processes utilizing downhole heaters are illustrated in U.S. Patent Nos. 2,634,961 to Ljungstrom; 2,732,195 to Ljungstrom; 2,780,450 to Ljungstrom; 2,789,805 to Ljungstrom; 2,923,535 to Ljungstrom; and 4,886,118 to Van Meurs et al.

[0007] Application of heat to oil shale formations is described in U.S. Patent Nos. 2,923,535 to Ljungstrom and 4,886,118 to Van Meurs et al. Heat may be applied to the oil shale formation to pyrolyze kerogen in the oil shale formation. The heat may also fracture the formation to increase permeability of the formation. The increased permeability may allow formation fluid to travel to a production well where the fluid is removed from the oil shale formation. In some processes disclosed by Ljungstrom, for example, an oxygen containing gaseous medium is introduced to a permeable stratum, preferably while still hot from a preheating step, to initiate combustion.

[0008] A heat source may be used to heat a subterranean formation. Electric heaters may be used to heat the subterranean formation by radiation and/or conduction. An electric heater may resistively heat an element. U.S. Patent No. 2,548,360 to Germain describes an electric heating element placed in a viscous oil in a wellbore. The heater element heats and thins the oil to allow the oil to be pumped from the wellbore. U.S. Patent No. 4,716,960 to Eastlund et al. describes electrically heating tubing of a petroleum well by passing a relatively low voltage current through the tubing to prevent formation of solids. U.S. Patent No. 5,065,818 to Van Egmond describes an electric heating element that is cemented into a well borehole without a casing surrounding the heating element.

[0009] U.S. Patent No. 6,023,554 to Vinegar et al. describes an electric heating element that is positioned in a casing. The heating element generates radiant energy that heats the casing. A granular solid fill material may be placed between the casing and the formation. The casing may conductively heat the fill material, which in turn conductively heats the formation.

[0010] U.S. Patent No. 4,570,715 to Van Meurs et al. describes an electric heating element. The heating element has an electrically conductive core, a surrounding layer of insulating material, and a surrounding metallic sheath. The conductive core may have a relatively low resistance at high temperatures. The insulating material may have electrical resistance, compressive strength,

and heat conductivity properties that are relatively high at high temperatures. The insulating layer may inhibit arcing from the core to the metallic sheath. The metallic sheath may have tensile strength and creep resistance properties that are relatively high at high temperatures.

[0011] U.S. Patent No. 5,060,287 to Van Egmond describes an electrical heating element having a copper-nickel alloy core.

[0012] Obtaining permeability in an oil shale formation between injection and production wells tends to be difficult because oil shale is often substantially impermeable. Many methods have attempted to link injection and production wells. These methods include: hydraulic fracturing such as methods investigated by Dow Chemical and Laramie Energy Research Center; electrical fracturing by methods investigated by Laramie Energy Research Center; acid leaching of limestone cavities by methods investigated by Dow Chemical; steam injection into permeable nahcolite zones to dissolve the nahcolite by methods investigated by Shell Oil and Equity Oil; fracturing with chemical explosives by methods investigated by Talley Energy Systems; fracturing with nuclear explosives by methods investigated by Project Bronco; and combinations of these methods. Many of these methods, however, have relatively high operating costs and lack sufficient injection capacity.

[0013] Large deposits of heavy hydrocarbons (heavy oil and/or tar) contained in relatively permeable formations (for example in tar sands) are found in North America, South America, Africa, and Asia. Tar can be surface-mined and upgraded to lighter hydrocarbons such as crude oil, naphtha, kerosene, and/or gas oil. Surface milling processes may further separate the bitumen from sand. The separated bitumen may be converted to light hydrocarbons using conventional refinery methods. Mining and upgrading tar sand is usually substantially more expensive than producing lighter hydrocarbons from conventional oil reservoirs.

[0014] In situ production of hydrocarbons from tar sand may be accomplished by heating and/or injecting a gas into the formation. U.S. Patent Nos. 5,211,230 to Ostapovich et al. and 5,339,897 to Leaute describe a horizontal production well located in an oil-bearing reservoir. A vertical conduit may be used to inject an oxidant gas into the reservoir for in situ combustion.

[0015] U.S. Patent No. 2,780,450 to Ljungstrom describes heating bituminous geological formations in situ to convert or crack a liquid tar-like substance into oils and gases.

[0016] U.S. Patent No. 4,597,441 to Ware et al. describes contacting oil, heat, and hydrogen simultaneously in a reservoir. Hydrogenation may enhance recovery of oil from the reservoir.

[0017] U.S. Patent No. 5,046,559 to Glandt and 5,060,726 to Glandt et al. describe preheating a portion of a tar sand formation between an injector well and a producer well. Steam may be injected from the injector well into the formation to produce hydrocarbons at the producer well.

[0018] As outlined above, there has been a significant amount of effort to develop methods and systems to economically produce hydrocarbons, hydrogen, and/or other products from hydrocarbon containing formations. At present, however, there are still many hydrocarbon containing formations from which hydrocarbons, hydrogen, and/or other products cannot be economically produced. Thus, there is still a need for improved methods and systems for production of hydrocarbons, hydrogen, and/or other products from various hydrocarbon containing formations.

SUMMARY

[0019] Embodiments described herein generally relate to systems, methods, and heaters for treating a subsurface formation. Embodiments described herein also generally relate to heaters that have novel components therein. Such heaters can be obtained by using the systems and methods described herein.

[0020] In certain embodiments, the invention provides one or more systems, methods, and/or heaters. In some embodiments, the systems, methods, and/or heaters are used for treating a subsurface formation.

[0021] In certain embodiments, the invention provides a heater, comprising: a heater section comprising iron, cobalt, and carbon; wherein the heater section has a Curie temperature (T_c) less than a phase transformation temperature, and the T_c is at least 740 °C; and wherein the heater section is configured to provide, when time varying current is applied to the heater section, an electrical resistance.

[0022] In some embodiments, the invention provides the heater section having at most 1% by weight of manganese, at most 1% by weight of nickel, at most 1% by weight of silicon, at most 1% by weight of vanadium, at most 1% by weight of titanium, and/or at most 1% by weight of manganese.

[0023] In some embodiments, the invention provides the heater section having a Curie temperature (T_c) less than a phase transformation temperature, and the T_c is at least 800 °C.

[0024] In some embodiments, the invention provides the heater section having at least 50% by weight iron, at least 9% by weight chromium and at least 0.1% by weight carbon.

[0025] In certain embodiments, the invention provides a system for coupling ends of elongated heaters, comprising: two elongated heaters with an end portion of one heater abutted or near to an end portion of the other heater, the elongated heaters comprising cores and one or more conductors substantially concentrically surrounding the cores, the cores having a lower melting point than the conductors, at least one end portion of at least one conductor having a beveled edge, and at least one end portion of at least one core having a recessed opening; a core coupling

material at least partially inside the recessed opening, the core coupling material extending between the two elongated heaters; and wherein the gap formed by the beveled edge is configured to be filled with a coupling material for coupling the one or more conductors.

[0026] In certain embodiments, the invention provides a system for coupling end portions of two elongated heater portions, comprising: a holding system configured to hold end portions of the two elongated heater portions so that the end portions are abutted together or located near each other; a shield for enclosing the end portions, the shield configured to inhibit oxidation during welding that joins the end portions together, the shield comprising a hinged door that, when closed, is configured to at least partially isolate the interior of the shield from the atmosphere, and the hinged door, when open, is configured to allow access to the interior of the shield; and one or more inert gas inlets configured to provide at least one inert gas to flush the system with inert gas during welding of the end portions.

[0027] In certain embodiments, the invention provides a heater, comprising: a ferromagnetic conductor; and an electrical conductor electrically coupled to the ferromagnetic conductor; wherein the heater is configured to provide a first amount of heat at a lower temperature and, the heater is configured to provide a second reduced amount of heat when the heater reaches a selected temperature, or enters a selected temperature range, at which the ferromagnetic conductor undergoes a phase transformation.

[0028] In certain embodiments, the invention provides a method for treating a hydrocarbon containing formation, comprising: providing heat for a first amount of time to a first hydrocarbon layer in the formation from a first heater located in an opening in the formation, the opening and the first heater having a substantially horizontal or inclined portion located in the first hydrocarbon layer in the formation and at least one connecting portion extending between the substantially horizontal or inclined portion and the surface; removing at least one connecting portion of the first heater from the opening; placing an isolation material in the opening such that the isolation material at least partially isolates the layer in which the substantially horizontal or inclined portion of the first heater is located; forming an additional substantially horizontal or inclined opening portion in a second hydrocarbon layer, the additional portion extending from at least one of the connecting portions of the opening; placing a second heater in the additional substantially horizontal opening portion; and providing heat from the second heater to the second hydrocarbon layer.

[0029] In certain embodiments, the invention provides a method for producing hydrocarbons from a subsurface formation, comprising: providing heat to the subsurface formation using an in situ heat treatment process; forming one or more formation particles, wherein the formation particles are formed during heating of the subsurface formation; and producing a fluid

comprising hydrocarbons and the formation particles from the subsurface formation, wherein the formation particles in the produced fluid comprise cenospheres and have an average particle size of at least 0.5 micrometers.

[0030] In certain embodiments, the invention provides a method of producing transportation fuel, comprising: providing formation fluid from a subsurface in situ heat treatment process, wherein the formation fluid has a boiling range distribution between -5 °C and 350 °C as determined by ASTM D5307; separating a liquid stream from the formation fluid; hydrotreating the separated liquid stream; distilling the hydrotreated liquid stream to produce a distilled stream, wherein the distilled stream has a boiling range distribution between 150 °C and 350 °C as determined by ASTM D5307; and combining the distilled liquid stream with one or more additives to produce transportation fuel.

[0031] In certain embodiments, the invention provides a method for treating a hydrocarbon containing formation, comprising: providing heat to the formation; producing heated fluid from the formation; and generating electricity from at least a portion of the heated fluid using a Kalina cycle.

[0032] In some embodiments, a method for forming a barrier around at least a portion of a treatment area in a subsurface formation includes introducing sulfur into one or more wellbores located inside a perimeter of a treatment area in the formation; and allowing at least some of the sulfur to move towards portions of the formation cooler than the melting point of sulfur to solidify the sulfur in the formation to form a barrier.

[0033] In some embodiments, in combination with other embodiments, the treatment area may have a permeability of at least 0.1 darcy, at least 1 darcy, at least 10 darcy, at least 100 darcy.

[0034] In some embodiments, in combination with other embodiments the permeability of the treatment has been increased by a solution mining process and/or by an in situ heat treatment process.

[0035] In some embodiments, in combination with other embodiments, the sulfur is provided as a liquid and/or a vapor into the formation. In some embodiments, in combination with other embodiments, the flow of sulfur is directed towards the perimeter of the treatment area. In some embodiments, in combination with other embodiments, the wellbores through which sulfur is introduced into the formation are located near the perimeter of the treatment area. In some embodiments, in combination with other embodiments, a low temperature barrier at least partially surrounding the treatment area enhances the solidification of the sulfur to form the barrier.

[0036] In some embodiments, a method of forming a barrier in a formation includes heating a portion of a formation adjacent to a plurality of wellbores to raise a temperature of the formation

adjacent to the wellbores above a melting temperature of sulfur and below a pyrolysis temperature of hydrocarbons in the formation, introducing molten sulfur into at least some of the wellbores; and allowing the sulfur to move outwards from the wellbores towards portions of the formation cooler than the melting temperature of sulfur so that the sulfur solidifies in the formation to form a barrier.

[0037] In some embodiments, in combination with other embodiments, at least one heater used to heat the portion of the formation adjacent the wellbores comprises a temperature limited heater. In some embodiments, in combination with other embodiments, a treatment area inside the barrier is solution mined and/or an in situ heat treatment process is used on a treatment area inside the barrier. In some embodiments, in combination with other embodiments, the barrier is formed between a first barrier and a treatment area used to produce formation fluid from the formation. In some embodiments, in combination with other embodiments, a temperature of the molten sulfur introduced into the formation is near the melting temperature of sulfur. In some embodiments, in combination with other embodiments, carbon dioxide is stored in the treatment area.

[0038] In certain embodiments, the invention provides a method for providing acidic gas to a subsurface formation, comprising: providing heat from one or more heaters to a portion of a subsurface formation; producing fluids from the formation using a heat treatment process, wherein the produced fluids comprise one or more acidic gases; and introducing at least a portion of one of the acidic gases into the formation, or into another formation, through one or more wellbores at a pressure below a lithostatic pressure of the formation in which the acidic gas is introduced.

[0001] In some embodiments a metal alloy composition may include from 18 percent to 22 percent by weight chromium; from 5 percent to 13 percent by weight nickel; between 3 percent and 10 percent by weight copper; from 1 percent to 10 percent by weight manganese; from 0.3 percent to 1 percent by weight silicon; from 0.5 percent to 1.5 percent by weight niobium; from 0.5 to 2 percent by weight tungsten; and from 38 percent to 63 percent by weight iron.

[0002] In some embodiments, a metal alloy composition may include from 18 percent to 22 percent by weight chromium; from 5 percent to 9 percent by weight nickel; from 1 percent to 6 percent by weight copper; from 0.5 percent to 1.5 percent by weight niobium; from 1 to 10 percent by weight manganese; from 0.5 to 1.5 percent by weight of tungsten; from 36 percent to 74 percent by weight iron; and precipitates of nanonitrides, wherein the ratio of tungsten to copper is between about 1/10 and 10/1.

[0003] In some embodiments, the invention describes a heater system may include a heat generating element and a canister surrounding the heat generating element least partially made

from material containing: from 18 percent to 22 percent by weight chromium; from 5 percent to 14 percent by weight nickel; from 1 percent to 10 percent by weight copper; from 0.5 percent to 1.5 percent by weight niobium; from 36 percent to 70.5 percent by weight iron; and precipitates of nanonitrides.

[0004] In some embodiments, the invention describes a system for heating a subterranean formation comprising a tubular, the tubular at least partially made from a material containing: from 18 percent to 22 percent by weight chromium; from 10 percent to 14 percent by weight nickel; from 1 percent to 10 percent by weight copper; from 0.5 percent to 1.5 percent by weight niobium; from 36 percent to 70.5 percent by weight iron; and precipitates of nanonitrides.

[0039] In certain embodiments, the invention provides a system for electrically insulating an overburden portion of a heater wellbore, comprising: the heater wellbore located in a subsurface formation; and an electrically insulating casing located in the overburden portion of the heater wellbore, the casing comprising at least one non-ferromagnetic material such that ferromagnetic effects are inhibited in the casing.

[0040] In certain embodiments, the invention provides a wellhead for coupling to a heater located in a wellbore in a subsurface formation, comprising: the heater located in the wellbore in the subsurface formation; and a wellhead coupled to the heater, the wellhead being configured to electrically couple the heater to one or more surface electrical components, and wherein the wellhead comprises at least one non-ferromagnetic material such that ferromagnetic effects are inhibited in the wellhead.

[0041] In certain embodiments, the invention provides a system for providing power to one or more subsurface heaters, comprising: an intermittent power source; a transformer coupled to the intermittent power source, the transformer being configured to transform power from the intermittent power source to power with appropriate operating parameters for the heaters; and a tap controller coupled to the transformer, the tap controller being configured to monitor and control the transformer so that a constant voltage is provided to the heaters from the transformer regardless of the load of the heaters and the power output provided by the intermittent power source.

[0042] In further embodiments, features from specific embodiments may be combined with features from other embodiments. For example, features from one embodiment may be combined with features from any of the other embodiments.

[0043] In further embodiments, treating a subsurface formation is performed using any of the methods, systems, or heaters described herein.

[0044] In further embodiments, additional features may be added to the specific embodiments described herein.

BRIEF DESCRIPTION OF THE DRAWINGS

[0045] Advantages of the present invention may become apparent to those skilled in the art with the benefit of the following detailed description and upon reference to the accompanying drawings in which:

[0046] FIG. 1 depicts an illustration of stages of heating a hydrocarbon containing formation.

[0047] FIG. 2 shows a schematic view of an embodiment of a portion of an in situ heat treatment system for treating a hydrocarbon containing formation.

[0048] FIG. 3 depicts a schematic of an embodiment of a Kalina cycle for producing electricity.

[0049] FIG. 4 depicts a schematic of an embodiment of a Kalina cycle for producing electricity.

[0050] FIG. 5 depicts a schematic representation of an embodiment of a system for treating the mixture produced from an in situ heat treatment process.

[0051] FIG. 5A depicts a schematic representation of an embodiment of a system for treating a liquid stream produced from an in situ heat treatment process.

[0052] FIG. 6 depicts a schematic representation of another embodiment of a system for treating a liquid stream produced from an in situ heat treatment process.

[0053] FIG. 7 depicts a schematic representation of an embodiment of a system for treating a liquid stream produced from an in situ heat treatment process.

[0054] FIG. 8 depicts a schematic representation of an embodiment of a system for forming and transporting tubing to a treatment area.

[0055] FIG. 9A depicts an embodiment of a drilling string including cutting structures positioned along the drilling string.

[0056] FIG. 9B depicts an embodiment of a drilling string including cutting structures positioned along the drilling string.

[0057] FIG. 9C depicts an embodiment of a drilling string including cutting structures positioned along the drilling string.

[0058] FIG. 10 depicts an embodiment of a drill bit including upward cutting structures.

[0059] FIG. 11 depicts an embodiment of a tubular including cutting structures positioned in a wellbore.

[0060] FIG. 12 depicts a schematic drawing of an embodiment of a drilling system.

[0061] FIG. 13 depicts a schematic drawing of an embodiment of a drilling system for drilling into a hot formation.

[0062] FIG. 14 depicts a schematic drawing of an embodiment of a drilling system for drilling into a hot formation.

[0063] FIG. 15 depicts a schematic drawing of an embodiment of a drilling system for drilling into a hot formation.

[0064] FIG. 16 depicts an embodiment of a freeze well for a circulated liquid refrigeration system, wherein a cutaway view of the freeze well is represented below ground surface.

[0065] FIG. 17A depicts an embodiment of a wellbore for introducing wax into a formation to form a wax grout barrier.

[0066] FIG. 17B depicts a representation of a wellbore drilled to an intermediate depth in a formation.

[0067] FIG. 17C depicts a representation of the wellbore drilled to the final depth in the formation.

[0068] FIG. 18 depicts an embodiment of a device for longitudinal welding of a tubular using ERW.

[0069] FIGS. 19, 20, and 21 depict cross-sectional representations of an embodiment of a temperature limited heater with an outer conductor having a ferromagnetic section and a non-ferromagnetic section.

[0070] FIGS. 22, 23, 24, and 25 depict cross-sectional representations of an embodiment of a temperature limited heater with an outer conductor having a ferromagnetic section and a non-ferromagnetic section placed inside a sheath.

[0071] FIGS. 26A and 26B depict cross-sectional representations of an embodiment of a temperature limited heater.

[0072] FIGS. 27A and 27B depict cross-sectional representations of an embodiment of a temperature limited heater.

[0073] FIGS. 28A and 28B depict cross-sectional representations of an embodiment of a temperature limited heater.

[0074] FIGS. 29A and 29B depict cross-sectional representations of an embodiment of a temperature limited heater.

[0075] FIGS. 30A and 30B depict cross-sectional representations of an embodiment of a temperature limited heater.

[0076] FIG. 31 depicts a cross-sectional representation of an embodiment of a composite conductor with a support member.

[0077] FIG. 32 depicts a cross-sectional representation of an embodiment of a composite conductor with a support member separating the conductors.

[0078] FIG. 33 depicts a cross-sectional representation of an embodiment of a composite conductor surrounding a support member.

[0079] FIG. 34 depicts a cross-sectional representation of an embodiment of a composite conductor surrounding a conduit support member.

[0080] FIG. 35 depicts a cross-sectional representation of an embodiment of a conductor-in-conduit heat source.

[0081] FIG. 36 depicts a cross-sectional representation of an embodiment of a removable conductor-in-conduit heat source.

[0082] FIG. 37 depicts an embodiment of a temperature limited heater in which the support member provides a majority of the heat output below the Curie temperature of the ferromagnetic conductor.

[0083] FIGS. 38 and 39 depict embodiments of temperature limited heaters in which the jacket provides a majority of the heat output below the Curie temperature of the ferromagnetic conductor.

[0084] FIG. 40 depicts a high temperature embodiment of a temperature limited heater.

[0085] FIG. 41 depicts hanging stress versus outside diameter for the temperature limited heater shown in FIG. 37 with 347H as the support member.

[0086] FIG. 42 depicts hanging stress versus temperature for several materials and varying outside diameters of the temperature limited heater.

[0087] FIGS. 43, 44, 45, and 46 depict examples of embodiments for temperature limited heaters that vary the materials and/or dimensions along the length of the heaters to provide desired operating properties.

[0088] FIGS. 47 and 48 depict examples of embodiments for temperature limited heaters that vary the diameter and/or materials of the support member along the length of the heaters to provide desired operating properties and sufficient mechanical properties.

[0089] FIGS. 49 and 49B depict cross-sectional representations of an embodiment of a temperature limited heater component used in an insulated conductor heater.

[0090] FIGS. 50 and 50B depict an embodiment of a system for installing heaters in a wellbore.

[0091] FIG. 50C depicts an embodiment of an insulated conductor with the sheath shorted to the conductors.

[0092] FIG. 51 depicts a top view representation of three insulated conductors in a conduit.

[0093] FIG. 52 depicts an embodiment of three-phase wye transformer coupled to a plurality of heaters.

[0094] FIG. 53 depicts a side view representation of an end section of three insulated conductors in a conduit.

[0095] FIG. 54 depicts one alternative embodiment of a heater with three insulated cores in a conduit.

[0096] FIG. 55 depicts another alternative embodiment of a heater with three insulated conductors and an insulated return conductor in a conduit.

[0097] FIG. 56 depicts an embodiment of an insulated conductor heater in a conduit with molten metal.

[0098] FIG. 57 depicts an embodiment of a substantially horizontal insulated conductor heater in a conduit with molten metal.

[0099] FIG. 58 depicts an embodiment for coupling together sections of a long temperature limited heater.

[0100] FIG. 59 depicts an embodiment of a shield for orbital welding sections of a long temperature limited heater.

[0101] FIG. 60 depicts a schematic representation of an embodiment of a shut off circuit for an orbital welding machine.

[0102] FIG. 61 depicts an embodiment of a temperature limited heater with a low temperature ferromagnetic outer conductor.

[0103] FIG. 62 depicts an embodiment of a temperature limited conductor-in-conduit heater.

[0104] FIG. 63 depicts a cross-sectional representation of an embodiment of a conductor-in-conduit temperature limited heater.

[0105] FIG. 64 depicts a cross-sectional representation of an embodiment of a conductor-in-conduit temperature limited heater.

[0106] FIG. 65 depicts a cross-sectional view of an embodiment of a conductor-in-conduit temperature limited heater.

[0107] FIG. 66 depicts a cross-sectional representation of an embodiment of a conductor-in-conduit temperature limited heater with an insulated conductor.

[0108] FIG. 67 depicts a cross-sectional representation of an embodiment of a conductor-in-conduit temperature limited heater with an insulated conductor.

[0109] FIG. 68 depicts an embodiment of a three-phase temperature limited heater with a portion shown in cross section.

[0110] FIG. 69 depicts an embodiment of temperature limited heaters coupled together in a three-phase configuration.

[0111] FIG. 70 depicts an embodiment of three heaters coupled in a three-phase configuration.

[0112] FIG. 71 depicts a side view representation of an embodiment of a substantially u-shaped three-phase heater.

[0113] FIG. 72 depicts a top view representation of an embodiment of a plurality of triads of three-phase heaters in a formation.

[0114] FIG. 73 depicts a top view representation of the embodiment depicted in FIG. 72 with production wells.

[0115] FIG. 74 depicts a top view representation of an embodiment of a plurality of triads of three-phase heaters in a hexagonal pattern.

[0116] FIG. 75 depicts a top view representation of an embodiment of a hexagon from FIG. 74.

[0117] FIG. 76 depicts an embodiment of triads of heaters coupled to a horizontal bus bar.

[0118] FIGS. 77 and 78 depict embodiments for coupling contacting elements of three legs of a heater.

[0119] FIG. 79 depicts an embodiment of a container with an initiator for melting the coupling material.

[0120] FIG. 80 depicts an embodiment of a container for coupling contacting elements with bulbs on the contacting elements.

[0121] FIG. 81 depicts an alternative embodiment of a container.

[0122] FIG. 82 depicts an alternative embodiment for coupling contacting elements of three legs of a heater.

[0123] FIG. 83 depicts a side-view representation of an embodiment for coupling contacting elements using temperature limited heating elements.

[0124] FIG. 84 depicts a side view representation of an alternative embodiment for coupling contacting elements using temperature limited heating elements.

[0125] FIG. 85 depicts a side view representation of another alternative embodiment for coupling contacting elements using temperature limited heating elements.

[0126] FIG. 86 depicts a side view representation of an alternative embodiment for coupling contacting elements of three legs of a heater.

[0127] FIG. 87 depicts a top view representation of the alternative embodiment for coupling contacting elements of three legs of a heater depicted in FIG. 86.

[0128] FIG. 88 depicts an embodiment of a contacting element with a brush contactor.

[0129] FIG. 89 depicts an embodiment for coupling contacting elements with brush contactors.

[0130] FIG. 90 depicts an embodiment of two temperature limited heaters coupled together in a single contacting section.

[0131] FIG. 91 depicts an embodiment of two temperature limited heaters with legs coupled in a contacting section.

[0132] FIG. 92 depicts an embodiment of three diads coupled to a three-phase transformer.

[0133] FIG. 93 depicts an embodiment of groups of diads in a hexagonal pattern.

[0134] FIG. 94 depicts an embodiment of diads in a triangular pattern.

[0135] FIG. 95 depicts a side-view representation of an embodiment of substantially u-shaped heaters.

[0136] FIG. 96 depicts a representational top view of an embodiment of a surface pattern of heaters depicted in FIG. 95.

[0137] FIG. 97 depicts a cross-sectional representation of substantially u-shaped heaters in a hydrocarbon layer.

[0138] FIG. 98 depicts a side view representation of an embodiment of substantially vertical heaters coupled to a substantially horizontal wellbore.

[0139] FIG. 99 depicts an embodiment of pluralities of substantially horizontal heaters coupled to bus bars in a hydrocarbon layer

[0140] FIG. 100 depicts an alternative embodiment of pluralities of substantially horizontal heaters coupled to bus bars in a hydrocarbon layer.

[0141] FIG. 101 depicts an enlarged view of an embodiment of a bus bar coupled to heater with connectors.

[0142] FIG. 102 depicts an enlarged view of an embodiment of a bus bar coupled to a heater with connectors and centralizers.

[0143] FIG. 103 depicts a cross-section representation of a connector coupling to a bus bar.

[0144] FIG. 104 depicts a three-dimensional representation of a connector coupling to a bus bar.

[0145] FIG. 105 depicts an embodiment of a substantially u-shaped heater that electrically isolates itself from the formation.

[0146] FIG. 106 depicts an embodiment of a single-ended, substantially horizontal heater that electrically isolates itself from the formation.

[0147] FIG. 107 depicts an embodiment of a single-ended, substantially horizontal heater that electrically isolates itself from the formation using an insulated conductor as the center conductor.

[0148] FIG. 108 depicts an embodiment of a single-ended, substantially horizontal insulated conductor heater that electrically isolates itself from the formation.

[0149] FIGS. 109 and 109B depict cross-sectional representations of an embodiment of an insulated conductor that is electrically isolated on the outside of the jacket.

[0150] FIGS. 110 and 110B depict an embodiment for using substantially u-shaped wellbores to time sequence heat two layers in a hydrocarbon containing formation.

[0151] FIGS. 111 and 111B depict an embodiment for using horizontal wellbores to time sequence heat two layers in a hydrocarbon containing formation.

[0152] FIG. 112 depicts an embodiment of a wellhead.

[0153] FIG. 113 depicts an embodiment of a dual continuous tubular suspension mechanism including threads cut on the dual continuous tubular over a built up portion.

[0154] FIG. 114 depicts an embodiment of a dual continuous tubular suspension mechanism including a built up portion on a continuous tubular.

[0155] FIGS. 115A-B depict embodiments of dual continuous tubular suspension mechanisms including slip mechanisms.

[0156] FIG. 116 depicts an embodiment of a dual continuous tubular suspension mechanism including a slip mechanism and a screw lock system.

[0157] FIG. 117 depicts an embodiment of a dual continuous tubular suspension mechanism including a slip mechanism and a screw lock system with counter sunk bolts.

[0158] FIG. 118 depicts an embodiment of a pass-through fitting used to suspend tubulars.

[0159] FIG. 119 depicts an embodiment of a dual slip mechanism for inhibiting movement of tubulars.

[0160] FIG. 120A-B depict embodiments of split suspension mechanisms and split slip assemblies for hanging dual continuous tubulars.

[0161] FIG. 121 depicts an embodiment of a dual slip mechanism for inhibiting movement of tubulars with a reverse configuration.

[0162] FIG. 122 depicts an embodiment of a two-part dual slip mechanism for inhibiting movement of tubulars.

[0163] FIG. 123 depicts an embodiment of a two-part dual slip mechanism for inhibiting movement of tubulars with separate locks.

[0164] FIG. 124 depicts an embodiment of a dual slip mechanism locking plate for inhibiting movement of tubulars.

[0165] FIG. 125 depicts an embodiment of a segmented dual slip mechanism with locking screws for inhibiting movement of tubulars.

[0166] FIG. 126 depicts a top view representation of the embodiment of a transformer showing the windings and core of the transformer.

[0167] FIG. 127 depicts a side view representation of the embodiment of the transformer showing the windings, the core, and the power leads.

[0168] FIG. 128 depicts an embodiment of a transformer in a wellbore.

[0169] FIG. 129 depicts an embodiment of a transformer in a wellbore with heat pipes.

[0170] FIG. 130 depicts a side view representation of an embodiment for producing mobilized fluids from a tar sands formation with a relatively thin hydrocarbon layer.

[0171] FIG. 131 depicts a side view representation of an embodiment for producing mobilized fluids from a tar sands formation with a hydrocarbon layer that is thicker than the hydrocarbon layer depicted in FIG. 130.

[0172] FIG. 132 depicts a side view representation of an embodiment for producing mobilized fluids from a tar sands formation with a hydrocarbon layer that is thicker than the hydrocarbon layer depicted in FIG. 131.

[0173] FIG. 133 depicts a side view representation of an embodiment for producing mobilized fluids from a tar sands formation with a hydrocarbon layer that has a shale break.

[0174] FIG. 134 depicts a top view representation of an embodiment for preheating using heaters for the drive process.

[0175] FIG. 135 depicts a side view representation of an embodiment for preheating using heaters for the drive process.

[0176] FIG. 136 depicts a representation of an embodiment for producing hydrocarbons from a tar sands formation.

[0177] FIG. 137 depicts a representation of an embodiment for producing hydrocarbons from multiple layers in a tar sands formation.

[0178] FIG. 138 depicts an embodiment for heating and producing from a formation with a temperature limited heater in a production wellbore.

[0179] FIG. 139 depicts an embodiment for heating and producing from a formation with a temperature limited heater and a production wellbore.

[0180] FIG. 140 depicts an embodiment of a heating/production assembly that may be located in a wellbore for gas lifting.

[0181] FIG. 141 depicts an embodiment of a heating/production assembly that may be located in a wellbore for gas lifting.

[0182] FIG. 142 depicts another embodiment of a heating/production assembly that may be located in a wellbore for gas lifting.

[0183] FIG. 143 depicts an embodiment of a production conduit and a heater.

[0184] FIG. 144 depicts an embodiment for treating a formation.

[0185] FIG. 145 depicts an embodiment of a heater well with selective heating.

[0186] FIG. 146 depicts a schematic representation of an embodiment of a downhole oxidizer assembly.

[0187] FIG. 147 depicts a cross-sectional representation of an embodiment of a downhole oxidizer including an insulating sleeve.

[0188] FIG. 148 depicts a cross-sectional representation of an embodiment of a downhole oxidizer with a gas cooled insulating sleeve.

[0189] FIG. 149 depicts a perspective view of an embodiment of a portion of an oxidizer of a downhole oxidizer assembly.

[0190] FIG. 150 depicts a cross-sectional representation of an embodiment of an oxidizer shield.

[0191] FIG. 151 depicts a cross-sectional representation of an embodiment of an oxidizer shield.

[0192] FIG. 152 depicts a cross-sectional representation of an embodiment of an oxidizer shield.

[0193] FIG. 153 depicts a cross-sectional representation of an embodiment of an oxidizer shield.

[0194] FIG. 154 depicts a cross-sectional representation of an embodiment of an oxidizer shield with multiple flame stabilizers.

[0195] FIG. 155 depicts a cross-sectional representation of an embodiment of an oxidizer shield.

[0196] FIG. 156 depicts a perspective representation of an embodiment of a sectioned oxidizer.

[0197] FIG. 157 depicts a perspective representation of an embodiment of a sectioned oxidizer.

[0198] FIG. 158 depicts a perspective representation of an embodiment of a sectioned oxidizer.

[0199] FIG. 159 depicts a perspective representation of an embodiment of a portion of an oxidizer of a downhole oxidizer assembly with louvered openings in the shield.

[0200] FIG. 160 depicts a cross-sectional representation of a portion of a shield with a louvered opening.

[0201] FIG. 161 depicts a cross-sectional of an embodiment of a first oxidizer of an oxidizer assembly.

[0202] FIG. 162 depicts a cross-sectional representation of an embodiment of a catalytic burner.

[0203] FIG. 163 depicts a cross-sectional representation of an embodiment of a catalytic burner with an igniter.

[0204] FIG. 164 depicts a schematic representation of an embodiment of a heater that uses coal as fuel.

[0205] FIG. 165 depicts a schematic representation of an embodiment of a heater that uses coal as fuel.

[0206] FIG. 166 depicts a schematic representation of a closed loop circulation system for heating a portion of a formation.

[0207] FIG. 167 depicts a plan view of wellbore entries and exits from a portion of a formation to be heated using a closed loop circulation system.

[0208] FIG. 168 depicts a schematic representation of an embodiment of an in situ heat treatment system that uses a nuclear reactor.

[0209] FIG. 169 depicts an elevational view of an in situ heat treatment system using pebble bed reactors.

[0210] FIG. 170 depicts a schematic of an embodiment of a U-shaped nuclear heater assembly.

[0211] FIG. 171 depicts a schematic of an embodiment of a nuclear heater assembly.

[0212] FIG. 172 depicts a schematic an embodiment of a middle portion of a nuclear heater assembly that includes pebble reactors and nuclear moderators.

[0213] FIG. 173 depicts a schematic of an embodiment of an end portion of a nuclear heater assembly that includes pebble reactors and nuclear moderators.

[0214] FIG. 174 depicts a schematic of an embodiment of a nuclear heater assembly that includes pebble reactors and spacers.

[0215] FIG. 175 depicts a schematic an embodiment of a nuclear heater assembly that includes stacked pebble reactors.

[0216] FIG. 176 depicts a schematic an embodiment of an embodiment of nuclear heater assembly.

[0217] FIG. 177 depicts a side view representation of an embodiment of a system for heating the formation that can use a closed loop circulation system and/or electrical heating.

[0218] FIG. 178 depicts a side view representation of an embodiment for an in situ staged heating and producing process for treating a tar sands formation.

[0219] FIG. 179 depicts a top view of a rectangular checkerboard pattern embodiment for the in situ staged heating and production process.

[0220] FIG. 180 depicts a top view of a ring pattern embodiment for the in situ staged heating and production process.

[0221] FIG. 181 depicts a top view of a checkerboard ring pattern embodiment for the in situ staged heating and production process.

[0222] FIG. 182 depicts a top view an embodiment of a plurality of rectangular checkerboard patterns in a treatment area for the in situ staged heating and production process.

[0223] FIG. 183 depicts a side view representations of embodiments for producing mobilized fluids from a hydrocarbon formation.

[0224] FIG. 184 depicts a schematic representation of a system for inhibiting migration of formation fluid from a treatment area.

[0225] FIG. 185 depicts an embodiment of a windmill for generating electricity for subsurface heaters.

[0226] FIG. 186 depicts an embodiment of a solution mining well.

[0227] FIG. 187 depicts a representation of a portion of a solution mining well.

[0228] FIG. 188 depicts a representation of a portion of a solution mining well.

[0229] FIG. 189 depicts an elevational view of a well pattern for solution mining and/or an in situ heat treatment process.

[0230] FIG. 190 depicts a representation of wells of an in situ heating treatment process for solution mining and producing hydrocarbons from a formation.

[0231] FIG. 191 depicts an embodiment for solution mining a formation.

[0232] FIG. 192 depicts an embodiment of a formation with nahcolite layers in the formation before solution mining nahcolite from the formation.

[0233] FIG. 193 depicts the formation of FIG. 192 after the nahcolite has been solution mined.

[0234] FIG. 194 depicts an embodiment of two injection wells interconnected by a zone that has been solution mined to remove nahcolite from the zone.

[0235] FIG. 195 depicts an embodiment for heating a formation with dawsonite in the formation.

[0236] FIG. 196 depicts a representation of an embodiment for solution mining with a steam and electricity cogeneration facility.

[0237] FIG. 197 depicts an embodiment of treating a hydrocarbon containing formation with a combustion front.

[0238] FIG. 198 depicts an embodiment of cross-sectional view of treating a hydrocarbon containing formation with a combustion front.

[0239] FIG. 199 depicts a schematic representation of a system for producing formation fluid and introducing sour gas into a subsurface formation.

[0240] FIG. 200 depicts electrical resistance versus temperature at various applied electrical currents for a 446 stainless steel rod.

[0241] FIG. 201 shows resistance profiles as a function of temperature at various applied electrical currents for a copper rod contained in a conduit of Sumitomo HCM12A.

[0242] FIG. 202 depicts electrical resistance versus temperature at various applied electrical currents for a temperature limited heater.

[0243] FIG. 203 depicts raw data for a temperature limited heater.

[0244] FIG. 204 depicts electrical resistance versus temperature at various applied electrical currents for a temperature limited heater.

[0245] FIG. 205 depicts power versus temperature at various applied electrical currents for a temperature limited heater.

[0246] FIG. 206 depicts electrical resistance versus temperature at various applied electrical currents for a temperature limited heater.

[0247] FIG. 207 depicts data of electrical resistance versus temperature for a solid 2.54 cm diameter, 1.8 m long 410 stainless steel rod at various applied electrical currents.

[0248] FIG. 208 depicts data of electrical resistance versus temperature for a composite 1.9 cm, 1.8 m long alloy 42-6 rod with a copper core (the rod has an outside diameter to copper diameter ratio of 2:1) at various applied electrical currents.

[0249] FIG. 209 depicts data of power output versus temperature for a composite 1.9 cm, 1.8 m long alloy 42-6 rod with a copper core (the rod has an outside diameter to copper diameter ratio of 2:1) at various applied electrical currents.

[0250] FIG. 210 depicts data for values of skin depth versus temperature for a solid 2.54 cm diameter, 1.8 m long 410 stainless steel rod at various applied AC electrical currents.

[0251] FIG. 211 depicts temperature versus time for a temperature limited heater.

[0252] FIG. 212 depicts temperature versus log time data for a 2.5 cm solid 410 stainless steel rod and a 2.5 cm solid 304 stainless steel rod.

[0253] FIG. 213 depicts experimentally measured resistance versus temperature at several currents for a temperature limited heater with a copper core, a carbon steel ferromagnetic conductor, and a stainless steel 347H stainless steel support member.

[0254] FIG. 214 depicts experimentally measured resistance versus temperature at several currents for a temperature limited heater with a copper core, an iron-cobalt ferromagnetic conductor, and a stainless steel 347H stainless steel support member.

[0255] FIG. 215 depicts experimentally measured power factor versus temperature at two AC currents for a temperature limited heater with a copper core, a carbon steel ferromagnetic conductor, and a 347H stainless steel support member.

[0256] FIG. 216 depicts experimentally measured turndown ratio versus maximum power delivered for a temperature limited heater with a copper core, a carbon steel ferromagnetic conductor, and a 347H stainless steel support member.

[0257] FIG. 217 depicts examples of relative magnetic permeability versus magnetic field for both the found correlations and raw data for carbon steel.

[0258] FIG. 218 shows the resulting plots of skin depth versus magnetic field for four temperatures and 400 A current.

[0259] FIG. 219 shows a comparison between the experimental and numerical (calculated) results for currents of 300 A, 400 A, and 500 A.

[0260] FIG. 220 shows the AC resistance per foot of the heater element as a function of skin depth at 1100 °F calculated from the theoretical model.

[0261] FIG. 221 depicts the power generated per unit length in each heater component versus skin depth for a temperature limited heater.

[0262] FIGS. 222A-C compare the results of theoretical calculations with experimental data for resistance versus temperature in a temperature limited heater.

[0263] FIG. 223 displays temperature of the center conductor of a conductor-in-conduit heater as a function of formation depth for a Curie temperature heater with a turndown ratio of 2:1.

[0264] FIG. 224 displays heater heat flux through a formation for a turndown ratio of 2:1 along with the oil shale richness profile.

[0265] FIG. 225 displays heater temperature as a function of formation depth for a turndown ratio of 3:1.

[0266] FIG. 226 displays heater heat flux through a formation for a turndown ratio of 3:1 along with the oil shale richness profile.

[0267] FIG. 227 displays heater temperature as a function of formation depth for a turndown ratio of 4:1.

[0268] FIG. 228 depicts heater temperature versus depth for heaters used in a simulation for heating oil shale.

[0269] FIG. 229 depicts heater heat flux versus time for heaters used in a simulation for heating oil shale.

[0270] FIG. 230 depicts accumulated heat input versus time in a simulation for heating oil shale.

[0271] FIG. 231 depicts a plot of heater power versus core diameter.

[0272] FIG. 232 depicts power, resistance, and current versus temperature for a heater with core diameters of 0.105".

[0273] FIG. 233 depicts actual heater power versus time during the simulation for three different heater designs.

[0274] FIG. 234 depicts heater element temperature (core temperature) and average formation temperature versus time for three different heater designs.

[0275] FIG. 235 depicts cumulative gas production and cumulative oil production versus time found from a STARS simulation using the heaters and heater pattern depicted in FIGS. 70 and 72.

[0276] FIG. 236 depicts experimental calculations of weight percentages of ferrite and austenite phases versus temperature for iron alloy TC3.

[0277] FIG. 237 depicts experimental calculations of weight percentages of ferrite and austenite phases versus temperature for iron alloy FM-4.

[0278] FIG. 238 depicts the Curie temperature and phase transformation temperature range for several iron alloys.

[0279] FIG. 239 depicts experimental calculations of weight percentages of ferrite and austenite phases versus temperature for an iron-cobalt alloy with 5.63% by weight cobalt and 0.4% by weight manganese.

[0280] FIG. 240 depicts experimental calculations of weight percentages of ferrite and austenite phases versus temperature for an iron-cobalt alloy with 5.63% by weight cobalt, 0.4% by weight manganese, and 0.01% carbon.

[0281] FIG. 241 depicts experimental calculations of weight percentages of ferrite and austenite phases versus temperature for an iron-cobalt alloy with 5.63% by weight cobalt, 0.4% by weight manganese, and 0.085% carbon.

[0282] FIG. 242 depicts experimental calculations of weight percentages of ferrite and austenite phases versus temperature for an iron-cobalt alloy with 5.63% by weight cobalt, 0.4% by weight manganese, 0.085% carbon, and 0.4% titanium.

[0283] FIG. 243 depicts experimental calculations of weight percentages of ferrite and austenite phases versus temperature for an iron-chromium alloy having 12.25% by weight chromium, 0.1% by weight carbon, 0.5% by weight manganese, and 0.5% by weight silicon.

[0284] FIG. 244 depicts experimental calculation of weight percentages of phases versus weight percentages of chromium in an alloy.

[0285] FIG. 245 depicts experimental calculation of weight percentages of phases versus weight percentages of silicon in an alloy.

[0286] FIG. 246 depicts experimental calculation of weight percentages of phases versus weight percentages of tungsten in an alloy.

[0287] FIG. 247 depicts experimental calculation of weight percentages of phases versus weight percentages of niobium in an alloy.

[0288] FIG. 248 depicts experimental calculation of weight percentages of phases versus weight percentages of carbon in an alloy.

[0289] FIG. 249 depicts experimental calculation of weight percentages of phases versus weight percentages of nitrogen in an alloy.

[0290] FIG. 250 depicts experimental calculation of weight percentages of phases versus weight percentages of titanium in an alloy.

[0291] FIG. 251 depicts experimental calculation of weight percentages of phases versus weight percentages of copper in an alloy.

[0292] FIG. 252 depicts experimental calculation of weight percentages of phases versus weight percentages of manganese in an alloy.

[0293] FIG. 253 depicts experimental calculation of weight percentages of phases versus weight percentages of nickel in an alloy.

[0294] FIG. 254 depicts experimental calculation of weight percentages of phases versus weight percentages of molybdenum in an alloy.

[0295] FIG. 255A depicts yield strengths and ultimate tensile strengths for different metals.

[0005] FIG. 255B depicts yield strengths for different metals.

[0006] FIG. 255C depicts ultimate tensile strengths for different metals.

[0007] FIG. 255D depicts yield strengths for different metals.

[0008] FIG. 255E depicts ultimate tensile strengths for different metals.

[0296] FIG. 256 depicts projected corrosion rates over a one-year period for several metals in a sulfidation atmosphere.

[0297] FIG. 257 depicts projected corrosion rates over a one-year period for 410 stainless steel and 410 stainless steel containing various amounts of cobalt in a sulfidation atmosphere.

[0298] FIG. 258 depicts an example of richness of an oil shale formation (gal/ton) versus depth (ft).

[0299] FIG. 259 depicts resistance per foot (mΩ/ft) versus temperature (°F) profile of the first heater example.

[0300] FIG. 260 depicts average temperature in the formation (°F) versus time (days) as determined by the simulation for the first example.

[0301] FIG. 261 depicts resistance per foot (mΩ/ft) versus temperature (°F) for the second heater example.

[0302] FIG. 262 depicts average temperature in the formation (°F) versus time (days) as determined by the simulation for the second example.

[0303] FIG. 263 depicts net heater energy input (Btu) versus time (days) for the second example.

[0304] FIG. 264 depicts power injection per foot (W/ft) versus time (days) for the second example.

[0305] FIG. 265 depicts resistance per foot (mΩ/ft) versus temperature (°F) for the third heater example.

[0306] FIG. 266 depicts average temperature in the formation (°F) versus time (days) as determined by the simulation for the third example.

[0307] FIG. 267 depicts cumulative energy injection (Btu) versus time (days) for each of the three heater examples.

[0308] FIG. 268 depicts average temperature (°F) versus time (days) for the third heater example with a 30 foot spacing between heaters in the formation as determined by the simulation.

[0309] FIG. 269 depicts average temperature (°F) versus time (days) for the fourth heater example using the heater configuration and pattern depicted in FIGS. 70 and 72 as determined by the simulation.

[0310] FIG. 270 depicts a temperature profile in the formation after 360 days using the STARS simulation.

[0311] FIG. 271 depicts an oil saturation profile in the formation after 360 days using the STARS simulation.

[0312] FIG. 272 depicts the oil saturation profile in the formation after 1095 days using the STARS simulation.

[0313] FIG. 273 depicts the oil saturation profile in the formation after 1470 days using the STARS simulation.

[0314] FIG. 274 depicts the oil saturation profile in the formation after 1826 days using the STARS simulation.

[0315] FIG. 275 depicts the temperature profile in the formation after 1826 days using the STARS simulation.

[0316] FIG. 276 depicts oil production rate and gas production rate versus time.

[0317] FIG. 277 depicts weight percentage of original bitumen in place (OBIP)(left axis) and volume percentage of OBIP (right axis) versus temperature (°C).

[0318] FIG. 278 depicts bitumen conversion percentage (weight percentage of (OBIP))(left axis) and oil, gas, and coke weight percentage (as a weight percentage of OBIP)(right axis) versus temperature (°C).

[0319] FIG. 279 depicts API gravity (°)(left axis) of produced fluids, blow down production, and oil left in place along with pressure (psig)(right axis) versus temperature (°C).

[0320] FIG. 280A-D depict gas-to-oil ratios (GOR) in thousand cubic feet per barrel ((Mcf/bbl)(y-axis) for versus temperature (°C)(x-axis) for different types of gas at a low temperature blow down (about 277 °C) and a high temperature blow down (at about 290 °C).

[0321] FIG. 281 depicts coke yield (weight percentage)(y-axis) versus temperature (°C)(x-axis).

[0322] FIG. 282A-D depict assessed hydrocarbon isomer shifts in fluids produced from the experimental cells as a function of temperature and bitumen conversion.

[0323] FIG. 283 depicts weight percentage (Wt%)(y-axis) of saturates from SARA analysis of the produced fluids versus temperature (°C)(x-axis).

[0324] FIG. 284 depicts weight percentage (Wt%)(y-axis) of n-C_7 of the produced fluids versus temperature (°C)(x-axis).

[0325] While the invention is susceptible to various modifications and alternative forms, specific embodiments thereof are shown by way of example in the drawings and may herein be described in detail. The drawings may not be to scale. It should be understood, however, that the drawings and detailed description thereto are not intended to limit the invention to the particular form disclosed, but on the contrary, the intention is to cover all modifications, equivalents and alternatives falling within the spirit and scope of the present invention as defined by the appended claims.

DETAILED DESCRIPTION

[0326] The following description generally relates to systems and methods for treating hydrocarbons in the formations. Such formations may be treated to yield hydrocarbon products, hydrogen, and other products.

[0327] "Alternating current (AC)" refers to a time-varying current that reverses direction substantially sinusoidally. AC produces skin effect electricity flow in a ferromagnetic conductor.

[0328] "API gravity" refers to API gravity at 15.5 °C (60 °F). API gravity is as determined by ASTM Method D6822 or ASTM Method D1298.

[0329] "ASTM" refers to American Standard Testing and Materials.

[0330] In the context of reduced heat output heating systems, apparatus, and methods, the term "automatically" means such systems, apparatus, and methods function in a certain way without the use of external control (for example, external controllers such as a controller with a temperature sensor and a feedback loop, PID controller, or predictive controller).

[0331] "Bare metal" and "exposed metal" refer to metals of elongated members that do not include a layer of electrical insulation, such as mineral insulation, that is designed to provide electrical insulation for the metal throughout an operating temperature range of the elongated member. Bare metal and exposed metal may encompass a metal that includes a corrosion inhibiter such as a naturally occurring oxidation layer, an applied oxidation layer, and/or a film. Bare metal and exposed metal include metals with polymeric or other types of electrical insulation that cannot retain electrical insulating properties at typical operating temperature of the elongated member. Such material may be placed on the metal and may be thermally degraded during use of the heater.

[0332] Boiling range distributions for the formation fluid and liquid streams described herein are as determined by ASTM Method D5307 or ASTM Method D2887. Content of hydrocarbon components in weight percent for paraffins, iso-paraffins, olefins, naphthenes and aromatics in the liquid streams is as determined by ASTM Method D6730. Content of aromatics in volume percent is as determined by ASTM Method D1319. Hydrogen Content in hydrocarbons in weight percent is as determined by ASTM Method D3343.

[0333] "Carbon number" refers to the number of carbon atoms in a molecule. A hydrocarbon fluid may include various hydrocarbons with different carbon numbers. The hydrocarbon fluid may be described by a carbon number distribution. Carbon numbers and/or carbon number distributions may be determined by true boiling point distribution and/or gas-liquid chromatography.

[0334] "Cenospheres" refers to hollow particulate that are formed in thermal processes at high temperatures when molten components are blown up like balloons by the volatilization of organic components.

[0335] "Chemically stability" refers to the ability of a formation fluid to be transported without components in the formation fluid reacting to form polymers and/or compositions that plug pipelines, valves, and/or vessels.

[0336] "Clogging" refers to impeding and/or inhibiting flow of one or more compositions through a process vessel or a conduit.

[0337] "Column X element" or "Column X elements" refer to one or more elements of Column X of the Periodic Table, and/or one or more compounds of one or more elements of Column X of the Periodic Table, in which X corresponds to a column number (for example, 13-18) of the Periodic Table. For example, "Column 15 elements" refer to elements from Column 15 of the Periodic Table and/or compounds of one or more elements from Column 15 of the Periodic Table.

[0338] "Column X metal" or "Column X metals" refer to one or more metals of Column X of the Periodic Table and/or one or more compounds of one or more metals of Column X of the Periodic Table, in which X corresponds to a column number (for example, 1-12) of the Periodic Table. For example, "Column 6 metals" refer to metals from Column 6 of the Periodic Table and/or compounds of one or more metals from Column 6 of the Periodic Table.

[0339] "Condensable hydrocarbons" are hydrocarbons that condense at 25 °C and one atmosphere absolute pressure. Condensable hydrocarbons may include a mixture of hydrocarbons having carbon numbers greater than 4. "Non-condensable hydrocarbons" are hydrocarbons that do not condense at 25 °C and one atmosphere absolute pressure. Non-condensable hydrocarbons may include hydrocarbons having carbon numbers less than 5.

[0340] "Coring" is a process that generally includes drilling a hole into a formation and removing a substantially solid mass of the formation from the hole.

[0341] "Cracking" refers to a process involving decomposition and molecular recombination of organic compounds to produce a greater number of molecules than were initially present. In cracking, a series of reactions take place accompanied by a transfer of hydrogen atoms between molecules. For example, naphtha may undergo a thermal cracking reaction to form ethene and H_2.

[0342] "Curie temperature" is the temperature above which a ferromagnetic material loses all of its ferromagnetic properties. In addition to losing all of its ferromagnetic properties above the Curie temperature, the ferromagnetic material begins to lose its ferromagnetic properties when an increasing electrical current is passed through the ferromagnetic material.

[0343] "Cycle oil" refers to a mixture of light cycle oil and heavy cycle oil. "Light cycle oil" refers to hydrocarbons having a boiling range distribution between 430 °F (221 °C) and 650 °F (343 °C) that are produced from a fluidized catalytic cracking system. Light cycle oil content is determined by ASTM Method D5307. "Heavy cycle oil" refers to hydrocarbons having a boiling range distribution between 650 °F (343 °C) and 800 °F (427 °C) that are produced from a fluidized catalytic cracking system. Heavy cycle oil content is determined by ASTM Method D5307.

[0344] "Diad" refers to a group of two items (for example, heaters, wellbores, or other objects) coupled together.

[0345] "Diesel" refers to hydrocarbons with a boiling range distribution between 260 °C and 343 °C (500-650 °F) at 0.101 MPa. Diesel content is determined by ASTM Method D2887.

[0346] "Enriched air" refers to air having a larger mole fraction of oxygen than air in the atmosphere. Air is typically enriched to increase combustion-supporting ability of the air.

[0347] "Fluid pressure" is a pressure generated by a fluid in a formation. "Lithostatic pressure" (sometimes referred to as "lithostatic stress") is a pressure in a formation equal to a weight per unit area of an overlying rock mass. "Hydrostatic pressure" is a pressure in a formation exerted by a column of water.

[0348] A "formation" includes one or more hydrocarbon containing layers, one or more non-hydrocarbon layers, an overburden, and/or an underburden. "Hydrocarbon layers" refer to layers in the formation that contain hydrocarbons. The hydrocarbon layers may contain non-hydrocarbon material and hydrocarbon material. The "overburden" and/or the "underburden" include one or more different types of impermeable materials. For example, the overburden and/or underburden may include rock, shale, mudstone, or wet/tight carbonate. In some embodiments of in situ heat treatment processes, the overburden and/or the underburden may include a hydrocarbon containing layer or hydrocarbon containing layers that are relatively impermeable and are not subjected to temperatures during in situ heat treatment processing that result in significant characteristic changes of the hydrocarbon containing layers of the overburden and/or the underburden. For example, the underburden may contain shale or mudstone, but the underburden is not allowed to heat to pyrolysis temperatures during the in situ heat treatment process. In some cases, the overburden and/or the underburden may be somewhat permeable.

[0349] "Formation fluids" refer to fluids present in a formation and may include pyrolyzation fluid, synthesis gas, mobilized hydrocarbon, and water (steam). Formation fluids may include hydrocarbon fluids as well as non-hydrocarbon fluids. The term "mobilized fluid" refers to fluids in a hydrocarbon containing formation that are able to flow as a result of thermal treatment of the formation. "Produced fluids" refer to fluids removed from the formation.

[0350] "Freezing point" of a hydrocarbon liquid refers to the temperature below which solid hydrocarbon crystals may form in the liquid. Freezing point is as determined by ASTM Method D5901.

[0351] "Gasoline hydrocarbons" refer to hydrocarbons having a boiling point range from 32 °C (90 °F) to about 204 °C (400 °F). Gasoline hydrocarbons include, but are not limited to, straight run gasoline, naphtha, fluidized or thermally catalytically cracked gasoline, VB gasoline, and coker gasoline. Gasoline hydrocarbons content is determined by ASTM Method D2887.

[0352] "Heat of Combustion" refers to an estimation of the net heat of combustion of a liquid. Heat of combustion is as determined by ASTM Method D3338.

[0353] A "heat source" is any system for providing heat to at least a portion of a formation substantially by conductive and/or radiative heat transfer. For example, a heat source may include electric heaters such as an insulated conductor, an elongated member, and/or a conductor disposed in a conduit. A heat source may also include systems that generate heat by burning a fuel external to or in a formation. The systems may be surface burners, downhole gas burners, flameless distributed combustors, and natural distributed combustors. In some embodiments, heat provided to or generated in one or more heat sources may be supplied by other sources of energy. The other sources of energy may directly heat a formation, or the energy may be applied to a transfer medium that directly or indirectly heats the formation. It is to be understood that one or more heat sources that are applying heat to a formation may use different sources of energy. Thus, for example, for a given formation some heat sources may supply heat from electric resistance heaters, some heat sources may provide heat from combustion, and some heat sources may provide heat from one or more other energy sources (for example, chemical reactions, solar energy, wind energy, biomass, or other sources of renewable energy). A chemical reaction may include an exothermic reaction (for example, an oxidation reaction). A heat source may also include a heater that provides heat to a zone proximate and/or surrounding a heating location such as a heater well.

[0354] A "heater" is any system or heat source for generating heat in a well or a near wellbore region. Heaters may be, but are not limited to, electric heaters, burners, combustors that react with material in or produced from a formation, and/or combinations thereof.

[0355] "Heavy hydrocarbons" are viscous hydrocarbon fluids. Heavy hydrocarbons may include highly viscous hydrocarbon fluids such as heavy oil, tar, and/or asphalt. Heavy hydrocarbons may include carbon and hydrogen, as well as smaller concentrations of sulfur, oxygen, and nitrogen. Additional elements may also be present in heavy hydrocarbons in trace amounts. Heavy hydrocarbons may be classified by API gravity. Heavy hydrocarbons generally have an API gravity below about 20°. Heavy oil, for example, generally has an API gravity of about 10-

20°, whereas tar generally has an API gravity below about 10°. The viscosity of heavy hydrocarbons is generally greater than about 100 centipoise at 15 °C. Heavy hydrocarbons may include aromatics or other complex ring hydrocarbons.

[0356] Heavy hydrocarbons may be found in a relatively permeable formation. The relatively permeable formation may include heavy hydrocarbons entrained in, for example, sand or carbonate. "Relatively permeable" is defined, with respect to formations or portions thereof, as an average permeability of 10 millidarcy or more (for example, 10 or 100 millidarcy). "Relatively low permeability" is defined, with respect to formations or portions thereof, as an average permeability of less than about 10 millidarcy. One darcy is equal to about 0.99 square micrometers. An impermeable layer generally has a permeability of less than about 0.1 millidarcy.

[0357] Certain types of formations that include heavy hydrocarbons may also be, but are not limited to, natural mineral waxes, or natural asphaltites. "Natural mineral waxes" typically occur in substantially tubular veins that may be several meters wide, several kilometers long, and hundreds of meters deep. "Natural asphaltites" include solid hydrocarbons of an aromatic composition and typically occur in large veins. In situ recovery of hydrocarbons from formations such as natural mineral waxes and natural asphaltites may include melting to form liquid hydrocarbons and/or solution mining of hydrocarbons from the formations.

[0358] "Hydrocarbons" are generally defined as molecules formed primarily by carbon and hydrogen atoms. Hydrocarbons may also include other elements such as, but not limited to, halogens, metallic elements, nitrogen, oxygen, and/or sulfur. Hydrocarbons may be, but are not limited to, kerogen, bitumen, pyrobitumen, oils, natural mineral waxes, and asphaltites. Hydrocarbons may be located in or adjacent to mineral matrices in the earth. Matrices may include, but are not limited to, sedimentary rock, sands, silicilytes, carbonates, diatomites, and other porous media. "Hydrocarbon fluids" are fluids that include hydrocarbons. Hydrocarbon fluids may include, entrain, or be entrained in non-hydrocarbon fluids such as hydrogen, nitrogen, carbon monoxide, carbon dioxide, hydrogen sulfide, water, and ammonia.

[0359] An "in situ conversion process" refers to a process of heating a hydrocarbon containing formation from heat sources to raise the temperature of at least a portion of the formation above a pyrolysis temperature so that pyrolyzation fluid is produced in the formation.

[0360] An "in situ heat treatment process" refers to a process of heating a hydrocarbon containing formation with heat sources to raise the temperature of at least a portion of the formation above a temperature that results in mobilized fluid, visbreaking, and/or pyrolysis of hydrocarbon containing material so that mobilized fluids, visbroken fluids, and/or pyrolyzation fluids are produced in the formation.

[0361] "Insulated conductor" refers to any elongated material that is able to conduct electricity and that is covered, in whole or in part, by an electrically insulating material.

[0362] "Karst" is a subsurface shaped by the dissolution of a soluble layer or layers of bedrock, usually carbonate rock such as limestone or dolomite. The dissolution may be caused by meteoric or acidic water. The Grosmont formation in Alberta, Canada is an example of a karst (or "karsted") carbonate formation.

[0363] "Kerogen" is a solid, insoluble hydrocarbon that has been converted by natural degradation and that principally contains carbon, hydrogen, nitrogen, oxygen, and sulfur. Coal and oil shale are typical examples of materials that contain kerogen. "Bitumen" is a non-crystalline solid or viscous hydrocarbon material that is substantially soluble in carbon disulfide. "Oil" is a fluid containing a mixture of condensable hydrocarbons.

[0364] "Kerosene" refers to hydrocarbons with a boiling range distribution between 204 °C and 260 °C at 0.101 MPa. Kerosene content is determined by ASTM Method D2887.

[0365] "Modulated direct current (DC)" refers to any substantially non-sinusoidal time-varying current that produces skin effect electricity flow in a ferromagnetic conductor.

[0366] "Naphtha" refers to hydrocarbon components with a boiling range distribution between 38 °C and 200 °C at 0.101 MPa. Naphtha content is determined by American Standard Testing and Materials (ASTM) Method D5307.

[0367] "Nitride" refers to a compound of nitrogen and one or more other elements of the Periodic Table. Nitrides include, but are not limited to, silicon nitride, boron nitride, or alumina nitride.

[0368] "Nitrogen compound content" refers to an amount of nitrogen in an organic compound. Nitrogen content is as determined by ASTM Method D5762.

[0369] "Octane Number" refers to a calculated numerical representation of the antiknock properties of a motor fuel compared to a standard reference fuel. A calculated octane number is determined by ASTM Method D6730.

[0370] "Olefins" are molecules that include unsaturated hydrocarbons having one or more non-aromatic carbon-carbon double bonds.

[0371] "Orifices" refer to openings, such as openings in conduits, having a wide variety of sizes and cross-sectional shapes including, but not limited to, circles, ovals, squares, rectangles, triangles, slits, or other regular or irregular shapes.

[0372] "Pebble" refers to one or more spheres, oval shapes, oblong shapes, irregular or elongated shapes.

[0373] "Periodic Table" refers to the Periodic Table as specified by the International Union of Pure and Applied Chemistry (IUPAC), November 2003. In the scope of this application, weight

of a metal from the Periodic Table, weight of a compound of a metal from the Periodic Table, weight of an element from the Periodic Table, or weight of a compound of an element from the Periodic Table is calculated as the weight of metal or the weight of element. For example, if 0.1 grams of MoO3 is used per gram of catalyst, the calculated weight of the molybdenum metal in the catalyst is 0.067 grams per gram of catalyst.

[0374] "Physical stability" refers the ability of a formation fluid to not exhibit phase separate or flocculation during transportation of the fluid. Physical stability is determined by ASTM Method D7060.

[0375] "Pyrolysis" is the breaking of chemical bonds due to the application of heat. For example, pyrolysis may include transforming a compound into one or more other substances by heat alone. Heat may be transferred to a section of the formation to cause pyrolysis.

[0376] "Pyrolyzation fluids" or "pyrolysis products" refers to fluid produced substantially during pyrolysis of hydrocarbons. Fluid produced by pyrolysis reactions may mix with other fluids in a formation. The mixture would be considered pyrolyzation fluid or pyrolyzation product. As used herein, "pyrolysis zone" refers to a volume of a formation (for example, a relatively permeable formation such as a tar sands formation) that is reacted or reacting to form a pyrolyzation fluid.

[0377] "Residue" refers to hydrocarbons that have a boiling point above 537 °C (1000 °F).

[0378] "Rich layers" in a hydrocarbon containing formation are relatively thin layers (typically about 0.2 m to about 0.5 m thick). Rich layers generally have a richness of about 0.150 L/kg or greater. Some rich layers have a richness of about 0.170 L/kg or greater, of about 0.190 L/kg or greater, or of about 0.210 L/kg or greater. Lean layers of the formation have a richness of about 0.100 L/kg or less and are generally thicker than rich layers. The richness and locations of layers are determined, for example, by coring and subsequent Fischer assay of the core, density or neutron logging, or other logging methods. Rich layers may have a lower initial thermal conductivity than other layers of the formation. Typically, rich layers have a thermal conductivity 1.5 times to 3 times lower than the thermal conductivity of lean layers. In addition, rich layers have a higher thermal expansion coefficient than lean layers of the formation.

[0379] "Smart well technology" or "smart wellbore" refers to wells that incorporate downhole measurement and/or control. For injection wells, smart well technology may allow for controlled injection of fluid into the formation in desired zones. For production wells, smart well technology may allow for controlled production of formation fluid from selected zones. Some wells may include smart well technology that allows for formation fluid production from selected zones and simultaneous or staggered solution injection into other zones. Smart well technology may include fiber optic systems and control valves in the wellbore. A smart wellbore used for an

in situ heat treatment process may be Westbay Multilevel Well System MP55 available from Westbay Instruments Inc. (Burnaby, British Columbia, Canada).

[0380] "Subsidence" is a downward movement of a portion of a formation relative to an initial elevation of the surface.

[0381] "Sulfur compound content" refers to an amount of sulfur in an organic compound. Sulfur content is as determined by ASTM Method D4294.

[0382] "Superposition of heat" refers to providing heat from two or more heat sources to a selected section of a formation such that the temperature of the formation at least at one location between the heat sources is influenced by the heat sources.

[0383] "Synthesis gas" is a mixture including hydrogen and carbon monoxide. Additional components of synthesis gas may include water, carbon dioxide, nitrogen, methane, and other gases. Synthesis gas may be generated by a variety of processes and feedstocks. Synthesis gas may be used for synthesizing a wide range of compounds.

[0384] "TAN" refers to a total acid number expressed as milligrams ("mg") of KOH per gram ("g") of sample. TAN is as determined by ASTM Method D3242.

[0385] "Tar" is a viscous hydrocarbon that generally has a viscosity greater than about 10,000 centipoise at 15 °C. The specific gravity of tar generally is greater than 1.000. Tar may have an API gravity less than 10°.

[0386] A "tar sands formation" is a formation in which hydrocarbons are predominantly present in the form of heavy hydrocarbons and/or tar entrained in a mineral grain framework or other host lithology (for example, sand or carbonate). Examples of tar sands formations include formations such as the Athabasca formation, the Grosmont formation, and the Peace River formation, all three in Alberta, Canada; and the Faja formation in the Orinoco belt in Venezuela.

[0387] "Temperature limited heater" generally refers to a heater that regulates heat output (for example, reduces heat output) above a specified temperature without the use of external controls such as temperature controllers, power regulators, rectifiers, or other devices. Temperature limited heaters may be AC (alternating current) or modulated (for example, "chopped") DC (direct current) powered electrical resistance heaters.

[0388] "Thermally conductive fluid" includes fluid that has a higher thermal conductivity than air at standard temperature and pressure (STP) (0 °C and 101.325 kPa).

[0389] "Thermal conductivity" is a property of a material that describes the rate at which heat flows, in steady state, between two surfaces of the material for a given temperature difference between the two surfaces.

[0390] "Thermal fracture" refers to fractures created in a formation caused by expansion or contraction of a formation and/or fluids in the formation, which is in turn caused by

increasing/decreasing the temperature of the formation and/or fluids in the formation, and/or by increasing/decreasing a pressure of fluids in the formation due to heating.

[0391] "Thermal oxidation stability" refers to thermal oxidation stability of a liquid. Thermal Oxidation Stability is as determined by ASTM Method D3241.

[0392] "Thickness" of a layer refers to the thickness of a cross section of the layer, wherein the cross section is normal to a face of the layer.

[0393] "Time-varying current" refers to electrical current that produces skin effect electricity flow in a ferromagnetic conductor and has a magnitude that varies with time. Time-varying current includes both alternating current (AC) and modulated direct current (DC).

[0394] "Triad" refers to a group of three items (for example, heaters, wellbores, or other objects) coupled together.

[0395] "Turndown ratio" for the temperature limited heater is the ratio of the highest AC or modulated DC resistance below the Curie temperature to the lowest resistance above the Curie temperature for a given current.

[0396] A "u-shaped wellbore" refers to a wellbore that extends from a first opening in the formation, through at least a portion of the formation, and out through a second opening in the formation. In this context, the wellbore may be only roughly in the shape of a "v" or "u", with the understanding that the "legs" of the "u" do not need to be parallel to each other, or perpendicular to the "bottom" of the "u" for the wellbore to be considered "u-shaped".

[0397] "Upgrade" refers to increasing the quality of hydrocarbons. For example, upgrading heavy hydrocarbons may result in an increase in the API gravity of the heavy hydrocarbons.

[0398] "Visbreaking" refers to the untangling of molecules in fluid during heat treatment and/or to the breaking of large molecules into smaller molecules during heat treatment, which results in a reduction of the viscosity of the fluid.

[0399] "Viscosity" refers to kinematic viscosity at 40 °C unless specified. Viscosity is as determined by ASTM Method D445.

[0400] "VGO" or "vacuum gas oil" refers to hydrocarbons with a boiling range distribution between 343 °C and 538 °C at 0.101 MPa. VGO content is determined by ASTM Method D5307.

[0401] A "vug" is a cavity, void or large pore in a rock that is commonly lined with mineral precipitates.

[0402] "Wax" refers to a low melting organic mixture, or a compound of high molecular weight that is a solid at lower temperatures and a liquid at higher temperatures, and when in solid form can form a barrier to water. Examples of waxes include animal waxes, vegetable waxes, mineral waxes, petroleum waxes, and synthetic waxes.

[0403] The term "wellbore" refers to a hole in a formation made by drilling or insertion of a conduit into the formation. A wellbore may have a substantially circular cross section, or another cross-sectional shape. As used herein, the terms "well" and "opening," when referring to an opening in the formation may be used interchangeably with the term "wellbore."

[0404] Hydrocarbons in formations may be treated in various ways to produce many different products. In certain embodiments, hydrocarbons in formations are treated in stages. FIG. 1 depicts an illustration of stages of heating the hydrocarbon containing formation. FIG. 1 also depicts an example of yield ("Y") in barrels of oil equivalent per ton (y axis) of formation fluids from the formation versus temperature ("T") of the heated formation in degrees Celsius (x axis).

[0405] Desorption of methane and vaporization of water occurs during stage 1 heating. Heating of the formation through stage 1 may be performed as quickly as possible. For example, when the hydrocarbon containing formation is initially heated, hydrocarbons in the formation desorb adsorbed methane. The desorbed methane may be produced from the formation. If the hydrocarbon containing formation is heated further, water in the hydrocarbon containing formation is vaporized. Water may occupy, in some hydrocarbon containing formations, between 10% and 50% of the pore volume in the formation. In other formations, water occupies larger or smaller portions of the pore volume. Water typically is vaporized in a formation between 160 °C and 285 °C at pressures of 600 kPa absolute to 7000 kPa absolute. In some embodiments, the vaporized water produces wettability changes in the formation and/or increased formation pressure. The wettability changes and/or increased pressure may affect pyrolysis reactions or other reactions in the formation. In certain embodiments, the vaporized water is produced from the formation. In other embodiments, the vaporized water is used for steam extraction and/or distillation in the formation or outside the formation. Removing the water from and increasing the pore volume in the formation increases the storage space for hydrocarbons in the pore volume.

[0406] In certain embodiments, after stage 1 heating, the formation is heated further, such that a temperature in the formation reaches (at least) an initial pyrolyzation temperature (such as a temperature at the lower end of the temperature range shown as stage 2). Hydrocarbons in the formation may be pyrolyzed throughout stage 2. A pyrolysis temperature range varies depending on the types of hydrocarbons in the formation. The pyrolysis temperature range may include temperatures between 250 °C and 900 °C. The pyrolysis temperature range for producing desired products may extend through only a portion of the total pyrolysis temperature range. In some embodiments, the pyrolysis temperature range for producing desired products may include temperatures between 250 °C and 400 °C or temperatures between 270 °C and 350 °C. If a temperature of hydrocarbons in the formation is slowly raised through the temperature range

from 250 °C to 400 °C, production of pyrolysis products may be substantially complete when the temperature approaches 400 °C. Average temperature of the hydrocarbons may be raised at a rate of less than 5 °C per day, less than 2 °C per day, less than 1 °C per day, or less than 0.5 °C per day through the pyrolysis temperature range for producing desired products. Heating the hydrocarbon containing formation with a plurality of heat sources may establish thermal gradients around the heat sources that slowly raise the temperature of hydrocarbons in the formation through the pyrolysis temperature range.

[0407] The rate of temperature increase through the pyrolysis temperature range for desired products may affect the quality and quantity of the formation fluids produced from the hydrocarbon containing formation. Raising the temperature slowly through the pyrolysis temperature range for desired products may inhibit mobilization of large chain molecules in the formation. Raising the temperature slowly through the pyrolysis temperature range for desired products may limit reactions between mobilized hydrocarbons that produce undesired products. Slowly raising the temperature of the formation through the pyrolysis temperature range for desired products may allow for the production of high quality, high API gravity hydrocarbons from the formation. Slowly raising the temperature of the formation through the pyrolysis temperature range for desired products may allow for the removal of a large amount of the hydrocarbons present in the formation as hydrocarbon product.

[0408] In some in situ heat treatment embodiments, a portion of the formation is heated to a desired temperature instead of slowly heating the temperature through a temperature range. In some embodiments, the desired temperature is 300 °C, 325 °C, or 350 °C. Other temperatures may be selected as the desired temperature. Superposition of heat from heat sources allows the desired temperature to be relatively quickly and efficiently established in the formation. Energy input into the formation from the heat sources may be adjusted to maintain the temperature in the formation substantially at the desired temperature. The heated portion of the formation is maintained substantially at the desired temperature until pyrolysis declines such that production of desired formation fluids from the formation becomes uneconomical. Parts of the formation that are subjected to pyrolysis may include regions brought into a pyrolysis temperature range by heat transfer from only one heat source.

[0409] In certain embodiments, formation fluids including pyrolyzation fluids are produced from the formation. As the temperature of the formation increases, the amount of condensable hydrocarbons in the produced formation fluid may decrease. At high temperatures, the formation may produce mostly methane and/or hydrogen. If the hydrocarbon containing formation is heated throughout an entire pyrolysis range, the formation may produce only small amounts of

hydrogen towards an upper limit of the pyrolysis range. After all of the available hydrogen is depleted, a minimal amount of fluid production from the formation will typically occur.

[0410] After pyrolysis of hydrocarbons, a large amount of carbon and some hydrogen may still be present in the formation. A significant portion of carbon remaining in the formation can be produced from the formation in the form of synthesis gas. Synthesis gas generation may take place during stage 3 heating depicted in FIG. 1. Stage 3 may include heating a hydrocarbon containing formation to a temperature sufficient to allow synthesis gas generation. For example, synthesis gas may be produced in a temperature range from about 400 °C to about 1200 °C, about 500 °C to about 1100 °C, or about 550 °C to about 1000 °C. The temperature of the heated portion of the formation when the synthesis gas generating fluid is introduced to the formation determines the composition of synthesis gas produced in the formation. The generated synthesis gas may be removed from the formation through a production well or production wells.

[0411] Total energy content of fluids produced from the hydrocarbon containing formation may stay relatively constant throughout pyrolysis and synthesis gas generation. During pyrolysis at relatively low formation temperatures, a significant portion of the produced fluid may be condensable hydrocarbons that have a high energy content. At higher pyrolysis temperatures, however, less of the formation fluid may include condensable hydrocarbons. More non-condensable formation fluids may be produced from the formation. Energy content per unit volume of the produced fluid may decline slightly during generation of predominantly non-condensable formation fluids. During synthesis gas generation, energy content per unit volume of produced synthesis gas declines significantly compared to energy content of pyrolyzation fluid. The volume of the produced synthesis gas, however, will in many instances increase substantially, thereby compensating for the decreased energy content.

[0412] FIG. 2 depicts a schematic view of an embodiment of a portion of the in situ heat treatment system for treating the hydrocarbon containing formation. The in situ heat treatment system may include barrier wells 200. Barrier wells are used to form a barrier around a treatment area. The barrier inhibits fluid flow into and/or out of the treatment area. Barrier wells include, but are not limited to, dewatering wells, vacuum wells, capture wells, injection wells, grout wells, freeze wells, or combinations thereof. In some embodiments, barrier wells 200 are dewatering wells. Dewatering wells may remove liquid water and/or inhibit liquid water from entering a portion of the formation to be heated, or to the formation being heated. In the embodiment depicted in FIG. 2, the barrier wells 200 are shown extending only along one side of heat sources 202, but the barrier wells typically encircle all heat sources 202 used, or to be used, to heat a treatment area of the formation.

[0413] Heat sources 202 are placed in at least a portion of the formation. Heat sources 202 may include heaters such as insulated conductors, conductor-in-conduit heaters, surface burners, flameless distributed combustors, and/or natural distributed combustors. Heat sources 202 may also include other types of heaters. Heat sources 202 provide heat to at least a portion of the formation to heat hydrocarbons in the formation. Energy may be supplied to heat sources 202 through supply lines 204. Supply lines 204 may be structurally different depending on the type of heat source or heat sources used to heat the formation. Supply lines 204 for heat sources may transmit electricity for electric heaters, may transport fuel for combustors, or may transport heat exchange fluid that is circulated in the formation. In some embodiments, electricity for an in situ heat treatment process may be provided by a nuclear power plant or nuclear power plants. The use of nuclear power may allow for reduction or elimination of carbon dioxide emissions from the in situ heat treatment process.

[0414] When the formation is heated, the heat input into the formation may cause expansion of the formation and geomechanical motion. The heat sources turned on before, at the same time, or during a dewatering process. Computer simulations may model formation response to heating. The computer simulations may be used to develop a pattern and time sequence for activating heat sources in the formation so that geomechanical motion of the formation does not adversely affect the functionality of heat sources, production wells, and other equipment in the formation.

[0415] Heating the formation may cause an increase in permeability and/or porosity of the formation. Increases in permeability and/or porosity may result from a reduction of mass in the formation due to vaporization and removal of water, removal of hydrocarbons, and/or creation of fractures. Fluid may flow more easily in the heated portion of the formation because of the increased permeability and/or porosity of the formation. Fluid in the heated portion of the formation may move a considerable distance through the formation because of the increased permeability and/or porosity. The considerable distance may be over 1000 m depending on various factors, such as permeability of the formation, properties of the fluid, temperature of the formation, and pressure gradient allowing movement of the fluid. The ability of fluid to travel considerable distance in the formation allows production wells 206 to be spaced relatively far apart in the formation.

[0416] Production wells 206 are used to remove formation fluid from the formation. In some embodiments, production well 206 includes a heat source. The heat source in the production well may heat one or more portions of the formation at or near the production well. In some in situ heat treatment process embodiments, the amount of heat supplied to the formation from the production well per meter of the production well is less than the amount of heat applied to the formation from a heat source that heats the formation per meter of the heat source. Heat applied

to the formation from the production well may increase formation permeability adjacent to the production well by vaporizing and removing liquid phase fluid adjacent to the production well and/or by increasing the permeability of the formation adjacent to the production well by formation of macro and/or micro fractures.

[0417] More than one heat source may be positioned in the production well. A heat source in a lower portion of the production well may be turned off when superposition of heat from adjacent heat sources heats the formation sufficiently to counteract benefits provided by heating the formation with the production well. In some embodiments, the heat source in an upper portion of the production well may remain on after the heat source in the lower portion of the production well is deactivated. The heat source in the upper portion of the well may inhibit condensation and reflux of formation fluid.

[0418] In some embodiments, the heat source in production well 206 allows for vapor phase removal of formation fluids from the formation. Providing heating at or through the production well may: (1) inhibit condensation and/or refluxing of production fluid when such production fluid is moving in the production well proximate the overburden, (2) increase heat input into the formation, (3) increase production rate from the production well as compared to a production well without a heat source, (4) inhibit condensation of high carbon number compounds (C6 and above) in the production well, and/or (5) increase formation permeability at or proximate the production well.

[0419] Subsurface pressure in the formation may correspond to the fluid pressure generated in the formation. As temperatures in the heated portion of the formation increase, the pressure in the heated portion may increase as a result of increased fluid generation and vaporization of water. Controlling rate of fluid removal from the formation may allow for control of pressure in the formation. Pressure in the formation may be determined at a number of different locations, such as near or at production wells, near or at heat sources, or at monitor wells.

[0420] In some hydrocarbon containing formations, production of hydrocarbons from the formation is inhibited until at least some hydrocarbons in the formation have been pyrolyzed. Formation fluid may be produced from the formation when the formation fluid is of a selected quality. In some embodiments, the selected quality includes an API gravity of at least about 20°, 30°, or 40°. Inhibiting production until at least some hydrocarbons are pyrolyzed may increase conversion of heavy hydrocarbons to light hydrocarbons. Inhibiting initial production may minimize the production of heavy hydrocarbons from the formation. Production of substantial amounts of heavy hydrocarbons may require expensive equipment and/or reduce the life of production equipment.

[0421] In some hydrocarbon containing formations, hydrocarbons in the formation may be heated to pyrolysis temperatures before substantial permeability has been generated in the heated portion of the formation. An initial lack of permeability may inhibit the transport of generated fluids to production wells 206. During initial heating, fluid pressure in the formation may increase proximate heat sources 202. The increased fluid pressure may be released, monitored, altered, and/or controlled through one or more heat sources 202. For example, selected heat sources 202 or separate pressure relief wells may include pressure relief valves that allow for removal of some fluid from the formation.

[0422] In some embodiments, pressure generated by expansion of pyrolysis fluids or other fluids generated in the formation may be allowed to increase although an open path to production wells 206 or any other pressure sink may not yet exist in the formation. The fluid pressure may be allowed to increase towards a lithostatic pressure. Fractures in the hydrocarbon containing formation may form when the fluid approaches the lithostatic pressure. For example, fractures may form from heat sources 202 to production wells 206 in the heated portion of the formation. The generation of fractures in the heated portion may relieve some of the pressure in the portion. Pressure in the formation may have to be maintained below a selected pressure to inhibit unwanted production, fracturing of the overburden or underburden, and/or coking of hydrocarbons in the formation.

[0423] After pyrolysis temperatures are reached and production from the formation is allowed, pressure in the formation may be varied to alter and/or control a composition of formation fluid produced, to control a percentage of condensable fluid as compared to non-condensable fluid in the formation fluid, and/or to control an API gravity of formation fluid being produced. For example, decreasing pressure may result in production of a larger condensable fluid component. The condensable fluid component may contain a larger percentage of olefins.

[0424] In some in situ heat treatment process embodiments, pressure in the formation may be maintained high enough to promote production of formation fluid with an API gravity of greater than 20°. Maintaining increased pressure in the formation may inhibit formation subsidence during in situ heat treatment. Maintaining increased pressure may facilitate vapor phase production of fluids from the formation. Vapor phase production may allow for a reduction in size of collection conduits used to transport fluids produced from the formation. Maintaining increased pressure may reduce or eliminate the need to compress formation fluids at the surface to transport the fluids in collection conduits to treatment facilities.

[0425] Maintaining increased pressure in a heated portion of the formation may surprisingly allow for production of large quantities of hydrocarbons of increased quality and of relatively low molecular weight. Pressure may be maintained so that formation fluid produced has a

minimal amount of compounds above a selected carbon number. The selected carbon number may be at most 25, at most 20, at most 12, or at most 8. Some high carbon number compounds may be entrained in vapor in the formation and may be removed from the formation with the vapor. Maintaining increased pressure in the formation may inhibit entrainment of high carbon number compounds and/or multi-ring hydrocarbon compounds in the vapor. High carbon number compounds and/or multi-ring hydrocarbon compounds may remain in a liquid phase in the formation for significant time periods. The significant time periods may provide sufficient time for the compounds to pyrolyze to form lower carbon number compounds.

[0426] Generation of relatively low molecular weight hydrocarbons is believed to be due, in part, to autogenous generation and reaction of hydrogen in a portion of the hydrocarbon containing formation. For example, maintaining an increased pressure may force hydrogen generated during pyrolysis into the liquid phase within the formation. Heating the portion to a temperature in a pyrolysis temperature range may pyrolyze hydrocarbons in the formation to generate liquid phase pyrolyzation fluids. The generated liquid phase pyrolyzation fluids components may include double bonds and/or radicals. Hydrogen (H_2) in the liquid phase may reduce double bonds of the generated pyrolyzation fluids, thereby reducing a potential for polymerization or formation of long chain compounds from the generated pyrolyzation fluids. In addition, H_2 may also neutralize radicals in the generated pyrolyzation fluids. Therefore, H_2 in the liquid phase may inhibit the generated pyrolyzation fluids from reacting with each other and/or with other compounds in the formation.

[0427] Formation fluid produced from production wells 206 may be transported through collection piping 208 to treatment facilities 210. Formation fluids may also be produced from heat sources 202. For example, fluid may be produced from heat sources 202 to control pressure in the formation adjacent to the heat sources. Fluid produced from heat sources 202 may be transported through tubing or piping to collection piping 208 or the produced fluid may be transported through tubing or piping directly to treatment facilities 210. Treatment facilities 210 may include separation units, reaction units, upgrading units, fuel cells, turbines, storage vessels, and/or other systems and units for processing produced formation fluids. The treatment facilities may form transportation fuel from at least a portion of the hydrocarbons produced from the formation. In some embodiments, the transportation fuel may be jet fuel, such as JP-8.

[0428] Formation fluid may be hot when produced from the formation through the production wells. Hot formation fluid may be produced during solution mining processes and/or during in situ heat treatment processes. In some embodiments, electricity may be generated using the heat of the fluid produced from the formation. Also, heat recovered from the formation after the in situ process may be used to generate electricity. The generated electricity may be used to supply

power to the in situ heat treatment process. For example, the electricity may be used to power heaters, or to power a refrigeration system for forming or maintaining a low temperature barrier. Electricity may be generated using a Kalina cycle or a modified Kalina cycle.

[0429] FIG. 3 depicts a schematic representation of a Kalina cycle that uses relatively high pressure aqua ammonia as the working fluid. In other embodiments, other fluids such as alkanes, hydrochlorofluorocarbons, hydrofluorocarbons, or carbon dioxide may be used as the working fluid. Hot produced fluid from the formation may pass through line 212 to heat exchanger 214. The produced fluid may have a temperature greater than about 100 °C. Line 216 from heat exchanger 214 may direct the produced fluid to a separator or other treatment unit. In some embodiments, the produced fluid is a mineral containing fluid produced during solution mining. In some embodiments, the produced fluid includes hydrocarbons produced using an in situ heat treatment process or using an in situ mobilization process. Heat from the produced fluid is used to evaporate aqua ammonia in heat exchanger 214.

[0430] Aqua ammonia from tank 218 is directed by pump 220 to heat exchanger 214 and heat exchanger 222. Aqua ammonia from heat exchangers 214, 222 passes to separator 224. Separator 224 forms a rich ammonia gas stream and a lean ammonia gas stream. The rich ammonia gas stream is sent to turbine 226 to generate electricity.

[0431] The lean ammonia gas stream from separator 224 passes through heat exchanger 222. The lean gas stream leaving heat exchanger 222 is combined with the rich ammonia gas stream leaving turbine 226. The combination stream is passed through heat exchanger 228 and returned to tank 218. Heat exchanger 228 may be water cooled. Heater water from heat exchanger 228 may be sent to a surface water reservoir through line 230.

[0432] FIG. 4 depicts a schematic representation of a modified Kalina cycle that uses lower pressure aqua ammonia as the working fluid. In other embodiments, other fluids such as alkanes, hydrochlorofluorcarbons, hydrofluorocarbons, or carbon dioxide may be used as the working fluid. Hot produced fluid from the formation may pass through line 212 to heat exchanger 214. The produced fluid may have a temperature greater than about 100 °C. Second heat exchanger 232 may further reduce the temperature of the produced fluid from the formation before the fluid is sent through line 216 to a separator or other treatment unit. Second heat exchanger may be water cooled.

[0433] Aqua ammonia from tank 218 is directed by pump 220 to heat exchanger 234. The temperature of the aqua ammonia from tank 218 is heated in heat exchanger 234 by transfer with a combined aqua ammonia stream from turbine 226 and separator 224. The aqua ammonia stream from heat exchanger 234 passes to heat exchanger 236. The temperature of the stream is raised again by transfer of heat with a lean ammonia stream that exits separator 224. The stream

then passes to heat exchanger 214. Heat from the produced fluid is used to evaporate aqua ammonia in heat exchanger 214. The aqua ammonia passes to separator 224.

[0434] Separator 224 forms a rich ammonia gas stream and a lean ammonia gas stream. The rich ammonia gas stream is sent to turbine 226 to generate electricity. The lean ammonia gas stream passes through heat exchanger 236. After heat exchanger 236, the lean ammonia gas stream is combined with the rich ammonia gas stream leaving turbine 226. The combined gas stream is passed through heat exchanger 234 to cooler 238. After cooler 238, the stream returns to tank 218.

[0435] Heating a portion of the subsurface formation may cause the mineral structure of the formation to change and form particles. The particles may be dispersed and/or become partially dissolved in the formation fluid. The particles may include metals and/or compounds of metals from Columns 1-2 and Columns 4-13 of the Periodic Table (for example, aluminum, silicon, magnesium, calcium, potassium sodium, beryllium, lithium, chromium, magnesium, copper, zirconium, and so forth). In certain embodiments, the particles include cenospheres. In some embodiments, the particles are coated, for example, with hydrocarbons of the formation fluid. In certain embodiments, the particles include zeolites.

[0436] A concentration of particles in formation fluid may range from about 1 ppm to about 3000 ppm, from about 50 ppm to about 2000 ppm, or from about 100 ppm to about 1000 ppm. The size of particles may range from about 0.5 micrometers to about 200 micrometers, from about 5 micrometers to about 150 micrometers, from about 10 micrometers to about 100 micrometers, or about 20 micrometers to about 50 micrometers.

[0437] In certain embodiments, formation fluid may include a distribution of particles. The distribution of particles may be, but is not limited to, a trimodal or a bimodal distribution. For example, a trimodal distribution of particles may include from about 1 ppm to about 50 ppm of particles with a size of about 5 micrometers to about 10 micrometers, from about 2 ppm to about 2000 ppm of particles with a size of about 50 micrometers to about 80 micrometers, and from about 1 ppm to about 100 ppm with a size of between about 100 micrometers and about 200 micrometers. A bimodal distribution of particles may include from about 1 ppm to about 60 ppm of particles with a size of between about 50 micrometers and about 60 micrometers and from about 2 ppm to about 2000 ppm of particles with a size between about 100 micrometers and about 200 micrometers.

[0438] In some embodiments, the particles may contact the formation fluid and catalyze formation of compounds having a carbon number of at most 25, at most 20, at most 12, or at most 8. In certain embodiments, zeolitic particles may assist in the oxidation and/or reduction of formation fluids to produce compounds not generally found in fluids produced using

conventional production methods. Contact of formation fluid with hydrogen in the presence of zeolitic particles may catalyze reduction of double bond compounds in the formation fluid.

[0439] In some embodiments, all or a portion of the particles in the produced fluid may be removed from the produced fluid. The particles may be removed by using a centrifuge, by washing, by acid washing, by filtration, by electrostatic precipitation, by froth flotation, and/or by another type of separation process.

[0440] Formation fluid produced from the in situ heat treatment process may be sent to the separator to split the stream into the in situ heat treatment process liquid stream and an in situ heat treatment process gas stream. In some embodiments, the formation fluid has a boiling range distribution between about -5 °C and about 350 °C, between about 5 °C and about 340 °C, between about 10 °C and about 330 °C, or between about 15 °C and about 320 °C.

[0441] The liquid stream and the gas stream may be further treated to yield desired products. When the liquid stream is treated using generally known conditions to produce commercial products, processing equipment may be adversely affected. For example, the processing equipment may clog. Examples of processes to produce commercial products include, but are not limited to, alkylation, distillation, catalytic reforming hydrocracking, hydrotreating, hydrogenation, hydrodesulfurization, catalytic cracking, delayed coking, gasification, or combinations thereof. Processes to produce hydrocarbon streams and/or other products are described in "Refining Processes 2000," Hydrocarbon Processing, Gulf Publishing Co., pp. 87-142. Examples of commercial hydrocarbon products include, but are not limited to, diesel, hydrocarbon gases, kerosene, naphtha, vacuum gas oil ("VGO"), or mixtures thereof.

[0442] Process equipment may become clogged or fouled by compositions in the in situ heat treatment process liquid. Clogging compositions may include, but are not limited to, hydrocarbons and/or solids produced from the in situ heat treatment process. Compositions that cause clogging may be formed during heating of the in situ heat treatment process liquid. The compositions may adhere to parts of the equipment and inhibit the flow of the liquid stream through processing units.

[0443] Solids that cause clogging may include, but are not limited to, organometallic compounds, inorganic compounds, minerals, mineral compounds, cenospheres, coke, semi-soot, and/or mixtures thereof. The solids may have a particle size such that conventional filtration may not remove the solids from the liquid stream. Hydrocarbons that cause clogging may include, but are not limited to, hydrocarbons that contain heteroatoms, aromatic hydrocarbons, cyclic hydrocarbons, cyclic di-olefins, and/or acyclic di-olefins. In some embodiments, solids and/or hydrocarbons present in the in situ heat treatment process liquid that cause clogging are partially soluble or insoluble in the situ heat treatment process liquid. In some embodiments, conventional

filtration of the liquid stream prior to or during heating is insufficient and/or ineffective for removal of all or some of the compositions that clog process equipment.

[0444] In some embodiments, clogging compositions are at least partially removed from the liquid stream by washing and/or desalting the liquid stream. In some embodiments, clogging of process equipment is inhibited by filtering at least a portion of the liquid stream through a nanofiltration system. In some embodiments, clogging of process equipment is inhibited by hydrotreating at least a portion of the liquid stream. In some embodiments, at least a portion the liquid stream is nanofiltered and then hydrotreated to remove composition that may clog and/or foul process equipment. The hydrotreated and/or nanofiltered liquid stream may be further processed to produce commercial products. In some embodiments, anti-fouling additives are added to the liquid stream to inhibit clogging of process equipment. Anti-fouling additives are described in U.S. Patent Nos. 5,648,305 to Mansfield et al.; 5,282,957 to Wright et al.; 5,173,213 to Miller et al.; 4,840,720 to Reid; 4,810,397 to Dvoracek; and 4,551,226 to Fern. Examples of commercially available additives include, but are not limited to, Chimec RO 303 Chimec RO 304, Chimec RO 305, Chimec RO 306, Chimec RO 307, Chimec RO 308, (available from Chimec, Rome, Italy), GE-Betz Thermal Flow 7R29 GE-Betz ProChem 3F28, Ge Betz ProChem 3F18 (available from GE Water and Process Technologies, Trevose, PA, U.S.A.).

[0445] FIGS. 5 and 5A depict schematic representations of an embodiment of a system for producing crude products and/or commercial products from the in situ heat treatment process liquid stream and/or the in situ heat treatment process gas stream. Formation fluid 320 enters fluid separation unit 322 and is separated into in situ heat treatment process liquid stream 324, in situ heat treatment process gas 240 and aqueous stream 326. In some embodiments, fluid separation unit 322 includes a quench zone. As produced formation fluid enters the quench zone, quenching fluid such as water, nonpotable water and/or other components may be added to the formation fluid to quench and/or cool the formation fluid to a temperature suitable for handling in downstream processing equipment. Quenching the formation fluid may inhibit formation of compounds that contribute to physical and/or chemical instability of the fluid (for example, inhibit formation of compounds that may precipitate from solution, contribute to corrosion, and/or fouling of downstream equipment and/or piping). The quenching fluid may be introduced into the formation fluid as a spray and/or a liquid stream. In some embodiments, the formation fluid is introduced into the quenching fluid. In some embodiments, the formation fluid is cooled by passing the fluid through a heat exchanger to remove some heat from the formation fluid. The quench fluid may be added to the cooled formation fluid when the temperature of the formation fluid is near or at the dew point of the quench fluid. Quenching the formation fluid near or at the dew point of the quench fluid may enhance solubilization of salts that may cause chemical and/or

physical instability of the quenched fluid (for example, ammonium salts). In some embodiments, an amount of water used in the quench is minimal so that salts of inorganic compounds and/or other components do not separate from the mixture. In separation unit 322, at least a portion of the quench fluid may be separated from the quench mixture and recycled to the quench zone with a minimal amount of treatment. Heat produced from the quench may be captured and used in other facilities. In some embodiments, vapor may be produced during the quench. The produced vapor may be sent to gas separation unit 328 and/or sent to other facilities for processing.

[0446] In situ heat treatment process gas 240 may enter gas separation unit 328 to separate gas hydrocarbon stream 330 from the in situ heat treatment process gas. The gas separation unit is, in some embodiments, a rectified adsorption and high pressure fractionation unit. Gas hydrocarbon stream 330 includes hydrocarbons having a carbon number of at least 3.

[0447] In situ heat treatment process liquid stream 324 enters liquid separation unit 332. In some embodiments, liquid separation unit 332 is not necessary. In liquid separation unit 332, separation of in situ heat treatment process liquid stream 324 produces gas hydrocarbon stream 336 and salty process liquid stream 338. Gas hydrocarbon stream 336 may include hydrocarbons having a carbon number of at most 5. A portion of gas hydrocarbon stream 336 may be combined with gas hydrocarbon stream 330. Salty process liquid stream 338 may be processed through desalting unit 340 to form liquid stream 334. Desalting unit 340 removes mineral salts and/or water from salty process liquid stream 338 using known desalting and water removal methods. In certain embodiments, desalting unit 340 is upstream of liquid separation unit 332.

[0448] Liquid stream 334 includes, but is not limited to, hydrocarbons having a carbon number of at least 5 and/or hydrocarbon containing heteroatoms (for example, hydrocarbons containing nitrogen, oxygen, sulfur, and phosphorus). Liquid stream 334 may include at least 0.001 g, at least 0.005 g, or at least 0.01 g of hydrocarbons with a boiling range distribution between about 95 °C and about 200 °C at 0.101 MPa; at least 0.01 g, at least 0.005 g, or at least 0.001 g of hydrocarbons with a boiling range distribution between about 200 °C and about 300 °C at 0.101 MPa; at least 0.001 g, at least 0.005 g, or at least 0.01 g of hydrocarbons with a boiling range distribution between about 300 °C and about 400 °C at 0.101 MPa; and at least 0.001 g, at least 0.005 g, or at least 0.01 g of hydrocarbons with a boiling range distribution between 400 °C and 650 °C at 0.101 MPa. In some embodiments, liquid stream 334 contains at most 10% by weight water, at most 5% by weight water, at most 1% by weight water, or at most 0.1% by weight water.

[0449] In some embodiments, the separated liquid stream may have a boiling range distribution between about 50 °C and about 350 °C, between about 60 °C and 340 °C, between about 70 °C

and 330 °C or between about 80 °C and 320°C. In some embodiments, the separated liquid stream has a boiling range distribution between 180 °C and 330 °C.

[0450] In some embodiments, at least 50%, at least 70%, or at least 90% by weight of the total hydrocarbons in the separated liquid stream have a carbon number from 8 to 13. The separated liquid stream may have from about 50% to about 100%, about 60% to about 95%, about 70% to about 90%, or about 75% to 85% by weight of liquid stream may have a carbon number distribution from 8 to 13. At least 50% by weight to the total hydrocarbon in the separated liquid stream may have a carbon number from about 9 to 12 or from 10 to 11.

[0451] In some embodiments the separated liquid stream has at most 15%, at most 10%, at most 5% by weight of naphthenes; at least 70%, at least 80%, or at least 90% by weight total paraffins; at most 5%, at most 3%, or at most 1% by weight olefins; and at most 30%, at most 20%, or at most 10% by weight aromatics.

[0452] In some embodiments, the separated liquid stream has a nitrogen compound content of at least 0.01%, at least 0.1% or at least 0.4% by weight nitrogen compound. The separated liquid stream may have a sulfur compound content of at least 0.01%, at least 0.5% or at least 1% by weight sulfur compound.

[0453] After exiting desalting unit 340, liquid stream 334 enters filtration system 342. In some embodiments, filtration system 342 is connected to the outlet of the desalting unit. Filtration system 342 separates at least a portion of the clogging compounds from liquid stream 334. In some embodiments, filtration system 342 is skid mounted. Skid mounting filtration system 342 may allow the filtration system to be moved from one processing unit to another. In some embodiments, filtration system 342 includes one or more membrane separators, for example, one or more nanofiltration membranes or one or more reserve osmosis membranes.

[0454] The membrane may be a ceramic membrane and/or a polymeric membrane. The ceramic membrane may be a ceramic membrane having a molecular weight cut off of at most 2000 Daltons (Da), at most 1000 Da, or at most 500 Da. Ceramic membranes do not have to swell in order to work under optimal conditions to remove the desired materials from a substrate (for example, clogging compositions from the liquid stream). In addition, ceramic membranes may be used at elevated temperatures. Examples of ceramic membranes include, but are not limited to, mesoporous titania, mesoporous gamma-alumina, mesoporous zirconia, mesoporous silica, and combinations thereof.

[0455] The polymeric membrane includes a top layer made of a dense membrane and a base layer (support) made of a porous membrane. The polymeric membrane may be arranged to allow the liquid stream (permeate) to flow first through the dense membrane top layer and then through the base layer so that the pressure difference over the membrane pushes the top layer onto the

base layer. The polymeric membrane is organophilic or hydrophobic membrane so that water present in the liquid stream is retained or substantially retained in the retentate.

[0456] The dense membrane layer may separate at least a portion of or substantially all of the clogging compositions from liquid stream 334. In some embodiments, the dense polymeric membrane has properties such that liquid stream 334 passes through the membrane by dissolving in and diffusing through its structure. At least a portion of the clogging particles may not dissolve and/or diffuse through the dense membrane, thus they are removed. The clogging particles may not dissolve and/or diffuse through the dense membrane because of the complex structure of the clogging particles and/or their high molecular weight. The dense membrane layer may include a cross-linked structure as described in WO 96/27430 to Schmidt et al. A thickness of the dense membrane layer may range from a 1 micrometer to 15 micrometers, from 2 micrometers to 10 micrometers, or from 3 micrometers to 5 micrometers.

[0457] The dense membrane may be made from polysiloxane, poly-di-methyl siloxane, poly-octyl-methyl siloxane, polyimide, polyaramide, poly-tri-methyl silyl propyne, or mixtures thereof. Porous base layers may be made of materials that provide mechanical strength to the membrane and may be any porous membrane used for ultra filtration, nanofiltration, or reverse osmosis. Examples of such materials are polyacrylonitrile, polyamideimide in combination with titanium oxide, polyetherimide, polyvinylidenediflouroide, polytetrafluoroethylene or combinations thereof.

[0458] During separation of clogging compositions from liquid stream 334, the pressure difference across the membrane may range from about 0.5 MPa to about 6 MPa, from about 1 MPa to about 5 MPa, or from about 2 MPa to about 4 MPa. A temperature of separation may range from the pour point of the liquid stream up to 100 °C, from about -20 °C to about 100 °C, from about 10 °C to about 90 °C, or from about 20 °C to about 85 °C. During a continuous operation, the permeate flux rate may be at most 50% of the initial flux, at most 70% of the initial flux, or at most 90% of the initial flux. A weight recovery of the permeate on feed may range from about 50% by weight to 97% by weight, from about 60% by weight to 90% by weight, or from about 70% by weight to 80% by weight.

[0459] Filtration system 342 may include one or more membrane separators. The membrane separators may include one or more membrane modules. When two or more membrane separators are used, they may be arranged in a parallel configuration to allow feed (retentate) from a first membrane separator to flow into a second membrane separator. Examples of membrane modules include, but are not limited to, spirally wound modules, plate and frame modules, hollow fibers, and tubular modules. Membrane modules are described in Encyclopedia of Chemical Engineering, 4th Ed., 1995, John Wiley & Sons Inc., Vol. 16, pages 158-164.

Examples of spirally wound modules are described in, for example, WO/2006/040307 to Boestert et al., U.S. Patent No. 5,102,551 to Pasternak; 5,093,002 to Pasternak; 5,275,726 to Feimer et al.; 5,458,774 to Mannapperuma; and 5,150,118 to Finkle et al.

[0460] In some embodiments, a spirally wound module is used when a dense membrane is used in filtration system 342. A spirally wound module may include a membrane assembly of two membrane sheets between which a permeate spacer sheet is sandwiched, and which membrane assembly is sealed at three sides. The fourth side is connected to a permeate outlet conduit such that the area between the membranes in fluid communication with the interior of the conduit. On top of one of the membranes a feed spacer sheet is arranged, and the assembly with feed spacer sheet is rolled up around the permeate outlet conduit, to form a substantially cylindrical spirally wound membrane module. The feed spacer may have a thickness of at least 0.6 mm, at least 1 mm, or at least 3 mm to allow sufficient membrane surface to be packed into a spirally wound module. In some embodiments, the feed spacer is a woven feed spacer. During operation, a feed mixture may be passed from one end of the cylindrical module between the membrane assemblies along the feed spacer sheet sandwiched between feed sides of the membranes. Part of the feed mixture passes through either one of the membrane sheets to the permeate side. The resulting permeate flows along the permeate spacer sheet into the permeate outlet conduit.

[0461] In some embodiments, the membrane separation is a continuous process. Liquid stream 334 passes over the membrane due to a pressure difference to obtain a filtered liquid stream 344 (permeate) and/or recycle liquid stream 346 (retentate). In some embodiments, filtered liquid stream 344 may have reduced concentrations of compositions and/or particles that cause clogging in downstream processing systems. Continuous recycling of recycle liquid stream 346 through nanofiltration system can increase the production of filtered liquid stream 344 to as much as 95% of the original volume of liquid stream 334. Recycle liquid stream 346 may be continuously recycled through a spirally wound membrane module for at least 10 hours, for at least one day, or for at least one week without cleaning the feed side of the membrane. Upon completion of the filtration, waste stream 348 (retentate) may include a high concentration of compositions and/or particles that cause clogging. Waste stream 348 exits filtration system 342 and is transported to other processing units such as, for example, a delayed coking unit and/or a gasification unit.

[0462] Filtered liquid stream 344 may exit filtration system 342 and enter one or more process units. Process units as described herein for the production of crude products and/or commercial products may be operated at the following temperatures, pressures, hydrogen source flows, liquid stream flows, or combinations thereof, or operated otherwise as known in the art. Temperatures range from about 200 °C to about 900 °C, from about 300 °C to about 800 °C, or from about 400 °C to about 700 °C. Pressures range from about 0.1 MPa to about 20 MPa, from about 1 MPa to

about 12 MPa, from about 4 MPa to about 10 MPa, or from about 6 MPa to about 8 MPa. Liquid hourly space velocities of the liquid stream range from about 0.1 h-1 to about 30 h-1, from about 0.5 h-1 to about 25 h-1, from about 1 h-1 to about 20 h-1, from about 1.5 h-1 to about 15 h-1, or from about 2 h-1 to about 10 h-1.

[0463] In FIG. 5, filtered liquid stream 344 and hydrogen source 246 enter hydrotreating unit 350. In some embodiments, hydrogen source 246 may be added to filtered liquid stream 344 before entering hydrotreating unit 350. In some embodiments, sufficient hydrogen is present in liquid stream 334 and hydrogen source 246 is not needed. In hydrotreating unit 350, contact of filtered liquid stream 344 with hydrogen source 246 in the presence of one or more catalysts produces liquid stream 352. Hydrotreating unit 350 may be operated such that all or at least a portion of liquid stream 352 is changed sufficiently to remove compositions and/or inhibit formation of compositions that may clog equipment positioned downstream of the hydrotreating unit 350. The catalyst used in hydrotreating unit 350 may be a commercially available catalyst. In some embodiments, hydrotreating of liquid stream 334 is not necessary.

[0464] In some embodiments, liquid stream 334 is contacted with hydrogen in the presence of one or more catalysts to change one or more desired properties of the crude feed to meet transportation and/or refinery specifications using known hydrodemetallation, hydrodesulfurization, hydrodenitrofication techniques. Other methods to change one or more desired properties of the crude feed are described in U.S. Published Patent Applications Nos. 2005-0133414; 2006-0231465; and 2007-0000810 to Bhan et al.; 2005-0133405 to Wellington et al.; and 2006-0289340 to Brownscombe et al.

[0465] In some embodiments, the hydrotreated liquid stream has a nitrogen compound content of at most 200 ppm by weight, at most 150 ppm, at most 110 ppm, at most 50 ppm, or at most 10 ppm of nitrogen compounds. The separated liquid stream may have a sulfur compound content of at most 100 ppm, at most 500 ppm, at most 300 ppm, at most 100 ppm, or at most 10 ppm by weight of sulfur compounds.

[0466] In some embodiments, hydrotreating unit 350 is a selective hydrogenation unit. In hydrotreating unit 350, liquid stream 334 and/or filtered liquid stream 344 are selectively hydrogenated such that di-olefins are reduced to mono-olefins. For example, liquid stream 334 and/or filtered liquid stream 344 is contacted with hydrogen in the presence of a DN-200 (Criterion Catalysts & Technologies, Houston Texas, U.S.A.) at temperatures ranging from 100 °C to 200 °C and total pressures of 0.1 MPa to 40 MPa to produce liquid stream 352. In some embodiments, filtered liquid stream 344 is hydrotreated at a temperature ranging from about 190 °C and about 200 °C at least 6 MPa. Liquid stream 352 includes a reduced content of di-olefins and an increased content of mono-olefins relative to the di-olefin and mono-olefin content of

liquid stream 334. The conversion of di-olefins to mono-olefins under these conditions is, in some embodiments, at least 50%, at least 60%, at least 80% or at least 90%. Liquid stream 352 exits hydrotreating unit 350 and enters one or more processing units positioned downstream of hydrotreating unit 350. The units positioned downstream of hydrotreating unit 350 may include distillation units, catalytic reforming units, hydrocracking units, hydrotreating units, hydrogenation units, hydrodesulfurization units, catalytic cracking units, delayed coking units, gasification units, or combinations thereof. In some embodiments, hydrotreating prior to fractionation is not necessary. In some embodiments, liquid stream 352 may be severely hydrotreated to remove undesired compounds from the liquid stream prior to fractionation. In certain embodiments, liquid stream 352 may be fractionated and then produced streams may each be hydrotreated to meet industry standards and/or transportation standards.

[0467] Liquid stream 352 may exit hydrotreating unit 350 and enter fractionation unit 354. In fractionation unit 354, liquid stream 352 may be distilled to form one or more crude products. Crude products include, but are not limited to, C3-C5 hydrocarbon stream 356, naphtha stream 358, kerosene stream 360, diesel stream 362, and bottoms stream 364. Fractionation unit 354 may be operated at atmospheric and/or under vacuum conditions.

[0468] As shown in FIG. 5A, fractionation unit 354 includes two or more zones operated at different temperatures and pressures. Operating the two zones at different temperatures and pressures may inhibit or substantially reduce fouling of fractionation columns, heat exchangers and/or other equipment associated with fractionation unit 354. Liquid stream 352 may enter first fractionation zone 2000. Fractionation zone KC200 may be operated at a temperature ranging from about 50 °C to about 350 °C, or from about 100 °C to 325 °C, or from about 150 °C to 300 °C at 0.101 MPa to separate compounds boiling above 350 ° from the liquid stream to produce one or more crude products including, but not limited to, C3-C5 hydrocarbon stream 356a, naphtha stream 358', kerosene stream 360', and diesel stream 362'. Hydrocarbons having a boiling point above 350 °C (for example bottoms stream 364') may enter second fractionation zone 2002. Second fractionation zone 2002 may be operated at temperatures greater than 350 °C at 0.101 MPa to separate form one or more crude products, including but not limited to, C3-C5 hydrocarbon stream 356b', naphtha stream 358", kerosene stream 360", diesel stream 362", and bottoms stream 364". In some embodiments, second fractionation zone 2002 is operated under vacuum. Bottoms stream 364, bottoms stream 364', and/or bottoms stream 364" generally includes hydrocarbons having a boiling range distribution of at least 340 °C at 0.101 MPa. In some embodiments, bottoms stream 364 is vacuum gas oil. In other embodiments, bottoms stream 364 bottoms stream 364', and/or bottoms stream 364" includes hydrocarbons with a boiling range distribution of at least 537 °C. One or more of the crude products may be sold

and/or further processed to gasoline or other commercial products. In certain embodiments, one or more of the crude products may be hydrotreated to meet industry standards and/or transportation standards.

[0469] As shown in FIG. 6 hydrotreated liquid stream may be treated in fractionation unit 354 to remove compounds boiling below 180 °C to produce distilled stream 355. Distilled stream 355 may have a boiling range distribution between about 140 °C and about 350 °C, between about 180 °C and about 330 °C, or between about 190 °C and about 310 °C. In some embodiments distilled stream 355 may be hydrotreated prior to fractionation to remove undesired compounds (for example, sulfur and/or nitrogen compounds). In certain embodiments, distilled stream 355 is sent to a hydrotreating unit and hydrotreated to meet transportation standards for metals, nitrogen compounds and/or sulfur compounds.

[0470] In some embodiments, at least 50%, at least 70%, or at least 90% by weight of the total hydrocarbons in distilled liquid stream 355 have a carbon number from 8 to 13. Distilled liquid stream 355 may have from about 50% to about 100%, about 60% to about 95%, about 70% to about 90%, or about 75% to 85% by weight may have a carbon number from 8 to 13. At least 50% by weight to the total hydrocarbon in distilled liquid stream 355 may have a carbon number from about 9 to 12 or from 10 to 11.

[0471] In some embodiments, hydrotreated and distilled liquid stream 355 has at most 15%, at most 10%, at most 5% by weight of naphthenes; at least 70%, at least 80%, or at least 90% by weight total paraffins; at most 5%, at most 3%, or at most 1% by weight olefins; and at most 25%, at most 20%, or at most 15% by weight aromatics.

[0472] In some embodiments, hydrotreated and distilled liquid stream 355 has a nitrogen compound content of at most 200 ppm by weight, at most 150 ppm, at most 110 ppm, at most 50 ppm, at most 10 ppm, or at most 5 ppm of nitrogen compounds. The hydrotreated and distilled liquid stream may have a sulfur content of at most 50 ppm, at most 30 ppm or at most 10 ppm by weight sulfur compound.

[0473] In some embodiments, hydrotreated and/or distilled liquid stream 355 has a wear scar diameter as measured by ASTM D5001, ranging from about 0.1 mm to about 0.9 mm, from about 0.2 mm to about 0.8 mm, or from 0.3 mm to about 0.7 mm. In some embodiments, hydrotreated and/or distilled liquid stream 355 has a wear scar diameter, as measured by ASTM D5001 of at most 0.85 mm, at most 0.8 mm, at most 0.6 mm, at most 0.5 mm, or at most 0.3 mm. A wear scar diameter, as determined by ASTM D5001, may indicate the hydrotreated and/or distilled stream may have acceptable lubrication properties for transportation fuel (for example, commercial aviation fuel, fuel for military purposes, JP-8 fuel, Jet A-1 fuel).

[0474] Hydrotreating to remove undesired compounds (for example, sulfur compounds and nitrogen compounds) from the liquid stream may decrease the liquid stream to be an effective lubricant (for example, lubricity properties when used as a transportation fuel). In some embodiments, hydrotreated and/or distilled liquid stream 355 has a minimal concentration and/or no detectable amounts of sulfur compounds. A low sulfur, nonadditized hydrotreated and/or distilled liquid stream 355 may have acceptable lubricity properties (for example, an acceptable wear scar diameter as measured by ASTM D5001). For example, the hydrotreated and distilled liquid stream may have a boiling range distribution from about 140 °C to about 260 °C, a sulfur content of at most 30 ppm by weight, and a wear scar diameter of at most 0.85 mm.

[0475] In some embodiments, naphtha stream 358, kerosene stream 360, diesel stream 362, distilled liquid stream 355 are evaluated to determine an amount, if any, of additives and/or hydrocarbons that may be added to prepare a fully formulated transportation fuel and/or lubricant. For example, a distilled stream made by the processes described herein was evaluated for use in military vehicles against Department of Defense standard MIL-DTL-83133E using ASTM test methods. The results of the test are listed in TABLE 1.

TABLE 1

		MIL-DTL-83133E Standard		
Specification Test	Liquid Stream	Min	Max	ASTM Test Method
Total Acid Number, mg KOH/g	0.007		0.015	D3242
Aromatics, % volume	11.4		25.0	D1319
Mercaptan Sulfur, % mass	0.000		0.001	D3227
Total Sulfur, % mass	0.00		0.3	D4294
Distillation:				D2887
IBP, °C 10% recovered, °C 20% recovered, °C 50% recovered, °C 90% recovered, °C EP, °C Residue, % volume Loss, % volume	180 188 191 199 215 229 0.9 0.3		report 186 Report Report Report 330 1.5 1.5	
Flash point, °C	60	38		D56
Cetane Index (calculated)	43.7		report	D976
Freeze Point, °C	-55		-47	D5901
Viscosity @ -20°C, cSt	4.4		8	D445
Viscosity @ -40°C, cSt	9.0			
Heat of Combustion (calculated), BTU/lb	18644	42.8		D3338
Hydrogen Content, % mass	14.0	13.4		D3343
Smoke Point, mm	26	25.0		D1322

		MIL-DTL-83133E Standard		
Specification Test	Liquid Stream	Min	Max	ASTM Test Method
Copper Strip Corrosion	1a			D130
Thermal Stability @ 260°C: Tube Deposit Rating Change in Pressure, mm Hg	 1 0			D3241
Existent Gum, mg/100 mL	1.4			D381
Water Reaction	1			D1094
Conductivity, pS/m	6*			D2624
Density @ 15°C	0.801	0.775	0.840	D1298
Lubricity (BOCLE), wear scar mm	<0.85			D5001

[0476] To enhance the use of the streams produced from formation fluid, hydrocarbons produced during fractionation of the liquid stream and hydrocarbon gases produced during separating the process gas may be combined to form hydrocarbons having a higher carbon number. The produced hydrocarbon gas stream may include a level of olefins acceptable for alkylation reactions.

[0477] In some embodiments, hydrotreated liquid streams and/or streams produced from fractions (for example, distillates and/or naphtha) are blended with the in situ heat treatment process liquid and/or formation fluid to produce a blended fluid. The blended fluid may have enhanced physical stability and chemical stability as compared to the formation fluid. The blended fluid may have a reduced amount of reactive species (for example, di-olefins, other olefins and/or compounds containing oxygen, sulfur and/or nitrogen) relative to the formation fluid. Thus, chemical stability of the blended fluid is enhanced. The blended fluid may decrease an amount of asphaltenes relative to the formation fluid. Thus, physical stability of the blended fluid is enhanced. The blended fluid may be a more a fungible feed than the formation fluid and/or the liquid stream produced from an in situ heat treatment process. The blended feed may be more suitable for transportation, for use in chemical processing units and/or for use in refining units than formation fluid.

[0478] In some embodiments, a fluid produced by methods described herein from an oil shale formation may be blended with heavy oil/tar sands in situ heat treatment process (IHTP) fluid. Since the oil shale liquid is substantially paraffinic and the heavy oil/tar sands IHTP fluid is substantially aromatic, the blended fluid exhibits enhanced stability. In certain embodiments, in situ heat treatment process fluid may be blended with bitumen to obtain a feed suitable for use in refining units. Blending of the IHTP fluid and/or bitumen with the produced fluid may enhance the chemical and/or physical stability of the blended product. Thus, the blend may be transported and/or distributed to processing units.

[0479] As shown in FIGS. 5, 5A, and 6, C3-C5 hydrocarbon stream 356 produced from fractionation unit 354 and hydrocarbon gas stream 330 enter alkylation unit 368. In alkylation unit 368, reaction of the olefins in hydrocarbon gas stream 330 (for example, propylene, butylenes, amylenes, or combinations thereof) with the iso-paraffins in C3-C5 hydrocarbon stream 356 produces hydrocarbon stream 370. In some embodiments, the olefin content in hydrocarbon gas stream 330 is acceptable and an additional source of olefins is not needed. Hydrocarbon stream 370 includes hydrocarbons having a carbon number of at least 4. Hydrocarbons having a carbon number of at least 4 include, but are not limited to, butanes, pentanes, hexanes, heptanes, and octanes. In certain embodiments, hydrocarbons produced from alkylation unit 368 have an octane number greater than 70, greater than 80, or greater than 90. In some embodiments, hydrocarbon stream 370 is suitable for use as gasoline without further processing.

[0480] In some embodiments, bottoms stream 364 may be hydrocracked to produce naphtha and/or other products. The resulting naphtha may, however, need reformation to alter the octane level so that the product may be sold commercially as gasoline. Alternatively, bottoms stream 364 may be treated in a catalytic cracker to produce naphtha and/or feed for an alkylation unit. In some embodiments, naphtha stream 358, kerosene stream 360, and diesel stream 362 have an imbalance of paraffinic hydrocarbons, olefinic hydrocarbons, and/or aromatic hydrocarbons. The streams may not have a suitable quantity of olefins and/or aromatics for use in commercial products. This imbalance may be changed by combining at least a portion of the streams to form combined stream 366 which has a boiling range distribution from about 38 °C to about 343 °C. Catalytically cracking combined stream 366 may produce olefins and/or other streams suitable for use in an alkylation unit and/or other processing units. In some embodiments, naphtha stream 358 is hydrocracked to produce olefins.

[0481] In FIG. 5 and FIG. 5A, combined stream 366 and bottoms stream 364 from fractionation unit 354 enters catalytic cracking unit 372. In FIG. 5A, combined stream 366 may include all or portions of streams 358', 360', 362', 358", 360", 362". Under controlled cracking conditions (for example, controlled temperatures and pressures), catalytic cracking unit 372 produces additional C3-C5 hydrocarbon stream 356', gasoline hydrocarbons stream 374, and additional kerosene stream 360'.

[0482] Additional C3-C5 hydrocarbon stream 356' may be sent to alkylation unit 368, combined with C3-C5 hydrocarbon stream 356, and/or combined with hydrocarbon gas stream 330 to produce gasoline suitable for commercial sale. In some embodiments, the olefin content in hydrocarbon gas stream 330 is acceptable and an additional source of olefins is not needed.

[0483] In some embodiments, an amount of the produced bottoms stream (for example, VGO) is too low to sustain operation of a hydrocracking unit or catalytic cracking unit and the concentration of olefins in the produced gas streams from a fractionation unit and/or a catalytic cracking unit (for example, from fractionation unit 354 and/or from catalytic cracking unit 372 in FIG. 5) may be too low to sustain operation of an alkylation unit. The naphtha produced from the fractionation unit may be treated to produce olefins for further processing in, for example, an alkylation unit. Reformulated gasoline produced by conventional naphtha reforming processes may not meet commercial specifications such as, for example, California Air Resources Board mandates when liquid stream produced from an in situ heat treatment process liquid is used as a feed stream. An amount of olefins in the naphtha may be saturated during conventional hydrotreating prior to the reforming naphtha process. Thus, reforming of all the hydrotreated naphtha may result in a higher than desired aromatics content in the gasoline pool for reformulated gasoline. The imbalance in the olefin and aromatic content in the reformed naphtha may be changed by producing sufficient alkylate from an alkylation unit to produce reformulated gasoline. Olefins (for example, propylene and butylenes) generated from fractionation and/or cracking of the naphtha may be combined with isobutane to produce gasoline. In addition, it has been found that catalytically cracking the naphtha and/or other fractionated streams produced in a fractionating unit requires additional heat because of a reduced amount of coke production relative to other feedstocks used in catalytic cracking units.

[0484] FIG. 7 depicts a schematic for treating liquid streams produced from an in situ heat treatment process stream to produce olefins and/or liquid streams. Similar processes to produce middle distillate and olefins are described in International Publication No. WO 2006/020547 and U.S. Patent Application Publication Nos. 2006-0191820 and 2006-0178546 to Mo et al. Liquid stream 376 enters catalytic cracking system 378. Liquid stream 376 may include, but is not limited to, liquid stream 334, hydrotreated liquid stream 352, filtered liquid stream 344, naphtha stream 358, kerosene stream 360, diesel stream 362, and bottoms stream 364 from the system depicted in FIG. 5, any hydrocarbon stream having a boiling range distribution between 65 °C and 800 °C, or mixtures thereof. In some embodiments, steam 272 enters catalytic cracking system 378 and may atomize and/or lift liquid stream 376 to enhance contact of the liquid stream with the catalytic cracking catalyst. A ratio of steam to atomize liquid stream 376 to feedstock may range from 0.01 to 2 by weight, or from 0.1 to 1 by weight.

[0485] In catalytic cracking system 378, liquid stream 376 is contacted with a catalytic cracking catalyst to produce one or more crude products. The catalytic cracking catalyst includes a selected catalytic cracking catalyst, at least a portion of used regenerated cracking catalyst stream 380, at least a portion of a regenerated cracking catalyst stream 382, or a mixture thereof. Used

regenerated cracking catalyst 380 includes a regenerated cracking catalyst that has been used in second catalytic cracking system 384. Second catalytic cracking system 384 may be used to crack hydrocarbons to produce olefins and/or other crude products. Hydrocarbons provided to second catalytic cracking system 384 may include C3-C5 hydrocarbons produced from the production wells, gasoline hydrocarbons, hydrowax, hydrocarbons produced from Fischer-Tropsch processes, biofuels, or combinations thereof. The use of a mixture of different types of hydrocarbon feed to the second catalytic cracking system may enhance C3-C5 olefin production to meet the alkylate demand. Thus, integration of the products with refinery processes may be enhanced. Second catalytic cracking system 384 may be a dense phase unit, a fixed fluidized bed unit, a riser, a combination of the above mentioned units, or any unit or configuration of units known in the art for cracking hydrocarbons.

[0486] Contact of the catalytic cracking catalyst and the liquid stream 376 in catalytic cracking system 378 produces a crude product and spent cracking catalyst. The crude product may include, but is not limited to, hydrocarbons having a boiling point distribution that is less than the boiling point distribution of liquid stream 376, a portion of liquid stream 376, or mixtures thereof. The crude product and spent catalyst enters separation system 386. Separation system 386 may include, for example, a distillation unit, a stripper, a filtration system, a centrifuge, or any device known in the art capable of separating the crude product from the spent catalyst.

[0487] Separated spent cracking catalyst stream 388 exits separation system 386 and enters regeneration unit 390. In regeneration unit 390, spent cracking catalyst is contacted with oxygen source 392 (for example, oxygen and/or air) under carbon burning conditions to produce regenerated cracking catalyst stream 382 and combustion gases 394. Combustion gases may form as a by-product of the removal of carbon and/or other impurities formed on the catalyst during the catalytic cracking process.

[0488] The temperature in regeneration unit 390 may range from about 621 °C to about 760 °C or from about 677 ° C to about 715 °C. The pressure in regeneration unit 390 may range from atmospheric to about 0.345 MPa or from about 0.034 to about 0.345 MPa. The residence time of the separated spent cracking catalyst in regeneration unit 390 ranges from about 1 to about 6 minutes or from or about 2 to about 4 minutes. The coke content on the regenerated cracking catalyst is less than the coke content on the separated spent cracking catalyst. Such coke content is less than 0.5% by weight, with the weight percent being based on the weight of the regenerated cracking catalyst excluding the weight of the coke content. The coke content of the regenerated cracking catalyst may range from 0.01% by weight to 0.5% by weight, 0.05% by weight to 0.3% by weight, or 0.1% by weight to 0.2% by weight.

[0489] In some embodiments, regenerated cracking catalyst stream 382 may be divided into two streams with at least a portion of regenerated cracking catalyst stream 382' exiting regeneration unit 390 and entering second catalytic cracking system 384. At least another portion of regenerated cracking catalyst stream 382 exits regenerator 390 and enters catalytic cracking system 378. The relative amount of the used regenerated cracking catalyst to the regenerated cracking catalyst is adjusted to provide for the desired cracking conditions within catalytic cracking system 378. Adjusting the ratio of used regenerated cracking catalyst to regenerated cracking catalyst may assist in the control of the cracking conditions in catalytic cracking system 378. A weight ratio of the used regenerated cracking catalyst to the regenerated cracking catalyst may range from 0.1:1 to 100:1, from 0.5:1 to 20:1, or from 1:1 to 10:1. For a system operated at steady state, the weight ratio of used regenerated cracking catalyst-to-regenerated cracking catalyst approximates the weight ratio of the at least a portion of regenerated cracking catalyst passing to the second catalytic cracking system 384 to the remaining portion of regenerated cracking catalyst that is mixed with liquid stream 376 introduced into catalytic cracking system 378, and, thus, the aforementioned ranges are also applicable to such weight ratio.

[0490] Crude product 396 exits separation system 386 and enters liquid separation unit 398. Liquid separation unit 398 may be any system known to those skilled in the art for recovering and separating the crude product into product streams such as, for example, gas stream 336', gasoline hydrocarbons stream 400, cycle oil stream 402, and bottom stream 404. In some embodiments, bottom stream 404 is recycled to catalytic cracking system 378. Liquid separation unit 398 may include components and/or units such as, for example, absorbers and strippers, fractionators, compressors and separators, or any combination of known systems for providing recovery and separation of products from the crude product. In some embodiments, at least a portion of light cycle oil stream 402 exits liquid separation unit 398 and enters second catalytic cracking system 378. In some embodiments, none of the light cycle oil stream is sent to the second catalytic cracking system. In some embodiments, at least a portion of gasoline hydrocarbons stream 400 exits liquid separation unit 398 and enters second catalytic cracking system 384. In some embodiments, none of the gasoline hydrocarbons stream is sent to the second catalytic cracking system. In some embodiments, gasoline hydrocarbons stream 400 is suitable for sale and/or for use in other processes.

[0491] At least a portion of gas oil hydrocarbon stream 406 (for example, vacuum gas oil) and/or portions of gasoline hydrocarbons stream 400 and at least a portion of light cycle oil stream 402 are sent to catalytic cracking system 384. The steams are catalytically cracked in the presence of steam 272' to produce crude olefin stream 408. Crude olefin stream 408 may include hydrocarbons having a carbon number of at least 2. In some embodiments, crude olefin stream

408 contains at least 30% by weight C2-C5 olefins, at least 40% by weight C2-C5 olefins, at least 50% by weight C2-C5 olefins, at least 70% by weight C2-C5 olefins, or at least 90% by weight C2-C5 olefins. The recycling of the gasoline hydrocarbons stream 400 into second catalytic cracking system 384 may provide for an additional conversion across the overall process system of gas oil hydrocarbon stream 406 to C2-C5 olefins.

[0492] In some embodiments, second catalytic cracking system 384 includes an intermediate reaction zone and a stripping zone that are in fluid communication with each other with the stripping zone located below the intermediate reaction zone. To provide for a high steam velocity within the stripping zone, as compared to its velocity within the intermediate reaction zone, the cross sectional area of the stripping zone is less than the cross sectional area of the intermediate reaction zone. The ratio of the stripping zone cross sectional area to the intermediate reaction zone cross sectional area may range from 0.1:1 to 0.9:1; from 0.2:1 to 0.8:1; or from 0.3:1 to 0.7:1.

[0493] In some embodiments, the geometry of the second catalytic cracking system is such that it is generally cylindrical in shape. The length-to-diameter ratio of the stripping zone of the catalytic cracking system is such as to provide for the desired high steam velocity within the stripping zone and to provide enough contact time within the stripping zone for the desired stripping of the used regenerated catalyst that is to be removed from the second catalytic cracking system. Thus, the length-to-diameter dimension of the stripping zone may range of from 1:1 to 25:1; from 2:1 to 15:1; or from 3:1 to 10:1.

[0494] In some embodiments, second catalytic cracking system 384 is operated or controlled independently from the operation or control of the catalytic cracking system 378. This independent operation or control of second catalytic cracking system 384 may improve overall conversion of the gasoline hydrocarbons into the desired products such as ethylene, propylene and butylenes. With the independent operation of second catalytic cracking system 384, the severity of catalytic cracking unit 378 may be reduced to optimize the yield of C2-C5 olefins. A temperature in second catalytic cracking system 384 may range from about 482 °C (900 ° F) to about 871 °C (1600 ° F), from about 510 °C. (950 °F) to about 871 °C (1600 °F), or from about 538 °C (1000 °F) to about 732 °C (1350 °F). The operating pressure of second catalytic cracking system 384 may range from atmospheric to about 0.345 MPa (50 psig) or from about 0.034 to 0.345 MPa (5 to 50 psig).

[0495] Addition of steam 272' into second catalytic cracking system 384 may assist in the operational control of the second catalytic cracking unit. In some embodiments, steam is not necessary. In some embodiments, the use of the steam for a given gasoline hydrocarbon conversion across the process system, and in the cracking of the gasoline hydrocarbons, may

provide for an improved selectivity toward C2-C5 olefin yield with an increase in propylene and butylenes yield relative to other catalytic cracking processes. A weight ratio of steam to gasoline hydrocarbons introduced into second catalytic cracking system 384 may be in the range of upwardly to or about 15:1; from 0.1:1 to 10:1; from 0.2:1 to 9:1; or from 0.5:1 to 8:1.

[0496] Crude olefin stream 408 enters olefin separation system 410. Olefin separation system 410 can be any system known to those skilled in the art for recovering and separating the crude olefin stream 408 into C2-C5 olefin product streams (for example, ethylene product stream 412, propylene product stream 414, and butylenes products stream 416). Olefin separation system 410 may include such systems as absorbers and strippers, fractionators, compressors and separators, or any combination of known systems or equipment providing for the recovery and separation of C2-C5 olefin products from fluid stream 408. In some embodiments, olefin streams 412, 414, 416 enter alkylation unit 368 to generate hydrocarbon stream 370. In some embodiments, hydrocarbon stream 370 has an octane number of at least 70, at least 80, or at least 90. In some embodiments, all or portions of one or more of streams 412, 414, 416 are transported to other processing units, such as polymerization units, for use as feedstocks.

[0497] In some embodiments, the crude product from the catalytic cracking system and the crude olefin stream from second catalytic cracking system may be combined. The combined stream may enter a single separation unit (for example, a combination of liquid separation system 398 and olefin separation system 410).

[0498] In FIG. 7, used cracking catalyst stream 380 exits second catalytic cracking system 384 and enters catalytic cracking system 378. Catalyst in used cracking catalyst stream 380 may include a slightly higher concentration of carbon than the concentration of carbon that is on the catalyst in regenerated cracking catalyst 382. A high concentration of carbon on the catalyst may partially deactivate the catalytic cracking catalysts which provides for an enhanced yield of olefins from the catalytic cracking system 378. Coke content of the used regenerated catalyst may be at least 0.1% by weight or at least 0.5% by weight. The coke content of the used regenerated catalyst may range from about 0.1% by weight to about 1% by weight or from about 0.1% by weight to about 0.6% by weight.

[0499] The catalytic cracking catalyst used in catalytic cracking system 378 and second catalytic cracking system 384 may be any fluidizable cracking catalyst known in the art. The fluidizable cracking catalyst may include a molecular sieve having cracking activity dispersed in a porous, inorganic refractory oxide matrix or binder. "Molecular sieve" refers to any material capable of separating atoms or molecules based on their respective dimensions. Molecular sieves suitable for use as a component of the cracking catalyst include pillared clays, delaminated clays, and crystalline aluminosilicates. In some embodiments, the cracking catalyst contains a crystalline

aluminosilicate. Examples of such aluminosilicates include Y zeolites, ultrastable Y zeolites, X zeolites, zeolite beta, zeolite L, offretite, mordenite, faujasite, and zeolite omega. In some embodiments, crystalline aluminosilicates for use in the cracking catalyst are X and/or Y zeolites. U.S. Patent No. 3,130,007 to Breck describes Y-type zeolites.

[0500] The stability and/or acidity of a zeolite used as a component of the cracking catalyst may be increased by exchanging the zeolite with hydrogen ions, ammonium ions, polyvalent metal cations, such as rare earth-containing cations, magnesium cations or calcium cations, or a combination of hydrogen ions, ammonium ions and polyvalent metal cations. The sodium content may be lowered until it is at most 0.8% by weight, at most 0.5% by weight and at most 0.3% by weight, calculated as Na_2O. Methods of carrying out the ion exchange are well known in the art.

[0501] The zeolite or other molecular sieve component of the cracking catalyst is combined with a porous, inorganic refractory oxide matrix, or binder to form a finished catalyst prior to use. The refractory oxide component in the finished catalyst may be silica-alumina, silica, alumina, natural or synthetic clays, pillared or delaminated clays, mixtures of one or more of these components, and the like. In some embodiments, the inorganic refractory oxide matrix includes a mixture of silica-alumina and clay such as kaolin, hectorite, sepiolite, and attapulgite. A finished catalyst may contain between about 5% by weight and about 40% by weight zeolite or other molecular sieve and greater than about 20 weight percent inorganic refractory oxide. In some embodiments, the finished catalyst may contain between about 10% and about 35% by weight zeolite or other molecular sieve, between about 10% and about 30% by weight inorganic refractory oxide, and between about 30% and about 70% by weight clay.

[0502] The crystalline aluminosilicate or other molecular sieve component of the cracking catalyst may be combined with the porous, inorganic refractory oxide component or a precursor thereof by any suitable technique known in the art including mixing, mulling, blending or homogenization. Examples of precursors that may be used include, but are not limited to, alumina, alumina sols, silica sols, zirconia, alumina hydrogels, polyoxycations of aluminum and zirconium, and peptized alumina. In some embodiments, the zeolite is combined with an alumino-silicate gel or sol or other inorganic, refractory oxide component, and the resultant mixture is spray dried to produce finished catalyst particles normally ranging in diameter between about 40 micrometers and about 80 micrometers. In some embodiments, the zeolite or other molecular sieve may be mulled or otherwise mixed with the refractory oxide component or precursor thereof, extruded and then ground into the desired particle size range. The finished catalyst may have an average bulk density between about 0.30 and about 0.90 gram per cubic centimeter and a pore volume between about 0.10 and about 0.90 cubic centimeter per gram.

[0503] In some embodiments, a ZSM-5 additive may be introduced into the intermediate cracking reactor of second catalytic cracking system 384. When a ZSM-5 additive is used along with the selected cracking catalyst in the intermediate cracking reactor, a yield of the lower olefins such as propylene and butylenes is enhanced. An amount of ZSM-5 ranges from at most 30% by weight, at most 20% by weight, or at most 18% by weight of the regenerated catalyst being introduced into second catalytic cracking system 384. An amount of ZSM-5 additive is introduced into second catalytic cracking system 384 may range from 1% to 30% by weight, 3% to 20% by weight, or 5% to 18% by weight of the regenerated cracking catalyst being introduced into second catalytic cracking system 384.

[0504] The ZSM-5 additive is a molecular sieve additive selected from the family of medium pore size crystalline aluminosilicates or zeolites. Molecular sieves that can be used as the ZSM-5 additive include, but are not limited to, medium pore zeolites as described in "Atlas of Zeolite Structure Types," Eds. W. H. Meier and D. H. Olson, Butterworth-Heineman, Third Edition, 1992. The medium pore size zeolites generally have a pore size from about 0.5 nm, to about 0.7 nm and include, for example, MFI, MFS, MEL, MTW, EUO, MTT, HEU, FER, and TON structure type zeolites (IUPAC Commission of Zeolite Nomenclature). Non-limiting examples of such medium pore size zeolites, include ZSM-5, ZSM-12, ZSM-22, ZSM-23, ZSM-34, ZSM-35, ZSM-38, ZSM-48, ZSM-50, silicalite, and silicalite 2. ZSM-5, are described in U.S. Pat. Nos. 3,702,886 to Argauer et al. and 3,770,614 to Graven.

[0505] ZSM-11 is described in U.S. Patent No. 3,709,979 to Chu; ZSM-12 in U.S. Patent No. 3,832,449 to Rosinski et al.; ZSM-21 and ZSM-38 in U.S. Patent No. 3,948,758 to Bonacci et al.; ZSM-23 in U.S. Patent No. 4,076,842 to Plank et al.; and ZSM-35 in U.S. Patent No. 4,016,245 to Plank et al. Other suitable molecular sieves include the silicoaluminophosphates (SAPO), such as SAPO-4 and SAPO-11 which is described in U.S. Patent No. 4,440,871 to Lok et al.; chromosilicates; gallium silicates, iron silicates; aluminum phosphates (ALPO), such as ALPO-11 described in U.S. Patent No. 4,310,440 to Wilson et al.; titanium aluminosilicates (TASO), such as TASO-45 described in U.S. Patent No. 4,686,029 to Pellet et al.; boron silicates, described in U.S. Patent No. 4,254,297 Frenken et al.; titanium aluminophosphates (TAPO), such as TAPO-11 described in U.S. Patent No. 4,500,651 to Lok et al.; and iron aluminosilicates.

[0506] U.S. Patent No. 4,368,114 to Chester et al. describes in detail the class of zeolites that can be suitable ZSM-5 additives. The ZSM-5 additive may be held together with a catalytically inactive inorganic oxide matrix component, in accordance with conventional methods.

[0507] In some embodiments, liquid streams produced from a heat treatment conversion process (for example liquid stream 334, and/or bottoms stream 364) and/or residue produced from units described in FIGS. 5 and 7 may be used as an energy source. Liquid stream 334 and/or the

residue may be gasified to produce gases (for example, hydrogen and/or carbon monoxide) which are burned (for example, burned in a turbine) and/or injected into a subsurface formation (for example, injection of produced carbon dioxide into a subsurface formation). In some embodiments, the liquid streams, formation fluids, and/or residue are heated in the presence of steam and/or a catalyst to produce hydrogen, carbon dioxide and/or carbon monoxide. In certain embodiments, the residue is de-asphalted to produce asphalt. The asphalt may be gasified. U.S. Patent Nos. 6,916,562 to Gosselink et al.; and 4,233,187 to Atwood et al.; and U.S. Patent Application Publication No. 2006-0289340 to Brownscombe et al. described methods to gasify hydrocarbon compounds.

[0508] In some embodiments, additives and/or heavier hydrocarbons may be combined with the processed liquid stream to prepare a finished fuel and/or lubricant to meet requirements for use in various industrial, commercial, and/or military applications (for example, fuel and/or lubricants for turbines, diesel trucks, aircraft, military vehicles,). Examples of additives include, but are not limited to, corrosion inhibitor, lubricity improver, static dissipate additive, fuel system icing inhibitor, antioxidant, detergents, surfactants, friction modifiers, or mixtures thereof.

[0509] In some embodiments, transportation fuel made from hydrocarbons obtained from an in situ heat treatment process and processed as described herein is suitable for use as fuel for aircraft and diesel fuel consuming vehicles and equipment. For example, for example the transportation fuel may be used in commercial utility cargo vehicles, high mobility multipurpose wheeled vehicles, military recovery vehicles, tanks, armored personnel carriers, and multi-ton diesel trucks. The transportation fuel may have a boiling range distribution between about 180 °C and about 330 °C as determined by ASTM D2887, an API gravity between 37 and 51 as determined by ASTM D1298, a freezing point of at most -47 °C as determined by ASTM D5901; a viscosity of at most 8.0 mm^2/s at -20 °C as determined by ASTM D445, a hydrogen content of at least 23.4% by weight as determined by ASTM D3343, an aromatics content of at most 25% by volume as determined by ASTM D1319, sulfur content of at most 0.3% by weight as determined by ASTM D4294, a net heat of combustion of at least 42.8 MJ/kg as determined by ASTM D3338; and thermal oxidation stability properties of: a heat tube deposit of at most 3 and a change in pressure drop of at most 25 mm Hg as determined by ASTM D3241.

[0510] During some in situ heat treatment processes, ammonia may be in formation fluid produced from the formation. Produced ammonia may be used for a number of purposes. In some embodiments, the ammonia or a portion of the ammonia may be used to produce hydrogen. In some embodiments, the Haber-Bosch process may be used to produce hydrogen. Ammonia may produce hydrogen and nitrogen according to the following equilibrium reaction:

[0511] (EQN. 1) $N_2 + 3H_2 \leftrightarrow 2NH_3$

[0512] The reaction may be a high temperature, high pressure, catalyzed reaction. The temperature may be from about 300 °C to about 800 °C. The pressure may be from about 80 bars to about 220 bars. The catalyst may be composed substantially of iron. The total amount of hydrogen produced may be increased by shifting the equilibrium towards hydrogen and nitrogen production. Equilibrium may be shifted to produce more nitrogen and hydrogen by removing nitrogen and/or hydrogen as they are produced.

[0513] Many wells are needed for treating the hydrocarbon formation using the in situ heat treatment process. In some embodiments, vertical or substantially vertical wells are formed in the formation. In some embodiments, horizontal or U-shaped wells are formed in the formation. In some embodiments, combinations of horizontal and vertical wells are formed in the formation.

[0514] A manufacturing approach for the formation of wellbores in the formation may be used due to the large number of wells that need to be formed for the in situ heat treatment process. The manufacturing approach may be particularly applicable for forming wells for in situ heat treatment processes that utilize u-shaped wells or other types of wells that have long non-vertically oriented sections. Surface openings for the wells may be positioned in lines running along one or two sides of the treatment area. FIG. 8 depicts a schematic representation of an embodiment of a system for forming wellbores of an in situ heat treatment process.

[0515] The manufacturing approach for the formation of wellbores may include: 1) delivering flat rolled steel to near site tube manufacturing plant that forms coiled tubulars and/or pipe for surface pipelines; 2) manufacturing large diameter coiled tubing that is tailored to the required well length using electrical resistance welding (ERW), wherein the coiled tubing has customized ends for the bottom hole assembly (BHA) and hang off at the wellhead; 3) deliver the coiled tubing to a drilling rig on a large diameter reel; 4) drill to total depth with coil and a retrievable bottom hole assembly; 5) at total depth, disengage the coil and hang the coil on the wellhead; 6) retrieve the BHA; 7) launch an expansion cone to expand the coil against the formation; 8) return empty spool to the tube manufacturing plant to accept a new length of coiled tubing; 9) move the gantry type drilling platform to the next well location; and 10) repeat.

[0516] In situ heat treatment process locations may be distant from established cities and transportation networks. Transporting formed pipe or coiled tubing for wellbores to the in situ process location may be untenable due to the lengths and quantity of tubulars needed for the in situ heat treatment process. One or more tube manufacturing facilities 2004 may be formed at or near to the in situ heat treatment process location. The tubular manufacturing facility may form plate steel into coiled tubing. The plate steel may be delivered to tube manufacturing facilities 2004 by truck, train, ship or other transportation system. In some embodiments, different

sections of the coiled tubing may be formed of different alloys. The tubular manufacturing facility may use ERW to longitudinally weld the coiled tubing.

[0517] Tube manufacturing facilities 2004 may be able to produce tubing having various diameters. Tube manufacturing facilities may initially be used to produce coiled tubing for forming wellbores. The tube manufacturing facilities may also be used to produce heater components, piping for transporting formation fluid to surface facilities, and other piping and tubing needs for the in situ heat treatment process.

[0518] Tube manufacturing facilities 2004 may produce coiled tubing used to form wellbores in the formation. The coiled tubing may have a large diameter. The diameter of the coiled tubing may be from about 4 inches to about 8 inches in diameter. In some embodiments, the diameter of the coiled tubing is about 6 inches in diameter. The coiled tubing may be placed on large diameter reels. Large diameter reels may be needed due to the large diameter of the tubing. The diameter of the reel may be from about 10 m to about 50 m. One reel may hold all of the tubing needed for completing a single well to total depth.

[0519] In some embodiments, tube manufacturing facilities 2004 has the ability to apply expandable zonal inflow profiler (EZIP) material to one or more sections of the tubing that the facility produces. The EZIP material may be placed on portions of the tubing that are to be positioned near and next to aquifers or high permeability layers in the formation. When activated, the EZIP material forms a seal against the formation may serves to inhibit migration of formation fluid between different layers. The use of EZIP layers may inhibit saline formation fluid from mixing with non-saline formation fluid.

[0520] The size of the reels used to hold the coiled tubing may prohibit transport of the reel using standard moving equipment and roads. Because tube manufacturing facility 2004 is at or near the in situ heat treatment location, the equipment used to move the coiled tubing to the well sites does not have to meet existing road transportation regulations and can be designed to move large reels of tubing. In some embodiments the equipment used to move the reels of tubing is similar to cargo gantries used to move shipping containers at ports and other facilities. In some embodiments, the gantries are wheeled units. In some embodiments, the coiled tubing may be moved using a rail system or other transportation system.

[0521] The coiled tubing may be moved from the tubing manufacturing facility to the well site using gantries 2006. Drilling gantry 2008 may be used at the well site. Several drilling gantries 2008 may be used to form wellbores at different locations. Supply systems for drilling fluid or other needs may be coupled to drilling gantries 2008 from central facilities 2010.

[0522] Drilling gantry 2008 or other equipment may be used to set the conductor for the well. Drilling gantry 2008 takes coiled tubing, passes the coiled tubing through a straightener, and a

BHA attached to the tubing is used to drill the wellbore to depth. In some embodiments, a composite coil is positioned in the coiled tubing at tube manufacturing facility 2004. The composite coil allows the wellbore to be formed without having drilling fluid flowing between the formation and the tubing. The composite coil also allows the BHA to be retrieved from the wellbore. The composite coil may be pulled from the tubing after wellbore formation. The composite coil may be returned to the tubing manufacturing facility to be placed in another length of coiled tubing. In some embodiments, the BHAs are not retrieved from the wellbores.

[0523] In some embodiments, drilling gantry 2008 takes the reel of coiled tubing from gantry 2006. In some embodiments, gantry 2006 is coupled to drilling gantry 2008 during the formation of the wellbore. For example, the coiled tubing may be fed from gantry 2006 to drilling gantry 2008, or the drilling gantry lifts the cargo gantry to a feed position and the tubing is fed from the cargo gantry to the drilling gantry.

[0524] The wellbore may be formed using the bottom hole assembly, coiled tubing and the drilling gantry. The BHA may be self-seeking to the destination. The BHA may form the opening at a fast rate. In some embodiments, the BHA forms the opening at a rate of about 100 m per hour.

[0525] After the wellbore is drilled to total depth, the tubing may be suspended from the wellhead. An expansion cone may be used to expand the tubular against the formation. In some embodiments, the drilling gantry is used to install a heater and/or other equipment in the wellbore.

[0526] When drilling gantry 2008 is finished at well site 2012, the drilling gantry may release gantry 2006 with the empty reel or return the empty reel to the gantry. Gantry 2006 may take the empty reel back to tube manufacturing facility 2004 to be loaded with another coiled tube. Gantries 2006 may move on looped path 2014 from tube manufacturing facility 2004 to well sites 2012 and back to the tube manufacturing facility.

[0527] Drilling gantry 2008 may be moved to the next well site. Global positioning satellite information, lasers and/or other information may be used to position the drilling gantry at desired locations. Additional wellbores may be formed until all of the wellbores for the in situ heat treatment process are formed.

[0528] In some embodiments, positioning and/or tracking system may be utilized to track gantries 2006, drilling gantries 2008, coiled tubing reels and other equipment and materials used to develop the in situ heat treatment location. Tracking systems may include bar code tracking systems to ensure equipment and materials arrive where and when needed.

[0529] Pieces of formation or rock may protrude or fall into the wellbore due to various failures including rock breakage or plastic deformation during and/or after wellbore formation.

Protrusions may interfere with drill string movement and/or the flow of drilling fluids. Protrusions may prevent running tubulars into the wellbore after the drill string has been removed from the wellbore. Significant amounts of material entering or protruding into the wellbore may cause wellbore integrity failure and/or lead to the drill string becoming stuck in the wellbore. Some causes of wellbore integrity failure may be in situ stresses and high pore pressures. Mud weight may be increased to hold back the formation and inhibit wellbore integrity failure during wellbore formation. When increasing the mud weight is not practical, the wellbore may be reamed.

[0530] Reaming the wellbore may be accomplished by moving the drill string up and down one joint while rotating and circulating. Picking the drill string up can be difficult because of material protruding into the borehole above the bit or BHA (bottom hole assembly). Picking up the drill string may be facilitated by placing upward facing cutting structures on the drill bit. Without upward facing cutting structures on the drill bit, the rock protruding into the borehole above the drill bit must be broken by grinding or crushing rather than by cutting. Grinding or crushing may induce additional wellbore failure.

[0531] Moving the drill string up and down may induce surging or pressure pulses that contribute to wellbore failure. Pressure surging or fluctuations may be aggravated or made worse by blockage of normal drilling fluid flow by protrusions into the wellbore. Thus, attempts to clear the borehole of debris may cause even more debris to enter the wellbore.

[0532] When the wellbore fails further up the drill string than one joint from the drill bit, the drill string must be raised more than one joint. Lifting more than one joint in length may require that joints be removed from the drill string during lifting and placed back on the drill string when lowered. Removing and adding joints requires additional time and labor, and increases the risk of surging as circulation is stopped and started for each joint connection.

[0533] In some embodiments, cutting structures may be positioned at various points along the drill string. Cutting structures may be positioned on the drill string at selected locations, for example, where the diameter of the drill string or BHA changes. FIG. 9A and FIG. 9B depict cutting structures 2020 located at or near diameter changes in drill string 2016 near to drill bit 2022 and/or BHA 2018. As depicted in FIG. 9C, cutting structures 2020 may be positioned at selected locations along the length of BHA 2018 and/or drill string 2016 that has a substantially uniform diameter. Cuttings formed by the cutting structures 2020 may be removed from the wellbore by the normal circulation used during the formation of the wellbore.

[0534] FIG. 10 depicts an embodiment of drill bit 2022 including cutting structures 2020. Drill bit 2022 includes downward facing cutting structures 2020b for forming the wellbore. Cutting

structures 2020a are upwardly facing cutting structures for reaming out the wellbore to remove protrusions from the wellbore.

[0535] In some embodiments, some cutting structures may be upwardly facing, some cutting structures may be downwardly facing, and/or some cutting structures may be oriented substantially perpendicular to the drill string. FIG. 11 depicts an embodiment of a portion of drilling string 2016 including upward facing cutting structures 2020a, downward facing cutting structures 2020b, and cutting structures 2020c that are substantially perpendicular to the drill string. Cutting structures 2020a may remove protrusions extending into wellbore 452 that would inhibit upward movement of drill string 2016. Cutting structures 2020a may facilitate reaming of wellbore 452 and/or removal of drill string 2016 from the wellbore for drill bit change, BHA maintenance and/or when total depth has been reached. Cutting structures 2020b may remove protrusions extending into wellbore 452 that would inhibit downward movement of drill string 2016. Cutting structures 2020c may ensure that enlarged diameter portions of drill string 2016 do not become stuck in wellbore 452.

[0536] Positioning downward facing cutting structures 2020b at various locations along a length of the drill string may allow for reaming of the wellbore while the drill bit forms additional borehole at the bottom of the wellbore. The ability to ream while drilling may avoid pressure surges in the wellbore caused by the lifting the drill string. Reaming while drilling allows the wellbore to be reamed without interrupting normal drilling operation. Reaming while drilling allows the wellbore to be formed in less time because a separate reaming operation is avoided. Upward facing cutting structures 2020a allow for easy removal of the drill string from the wellbore.

[0537] In some embodiments, the drill string includes a plurality of cutting structures positioned along the length of the drill string, but not necessarily along the entire length of the drill string. The cutting structures may be positioned at regular or irregular intervals along the length of the drill string. Positioning cutting structures along the length of the drill string allows the entire wellbore to be reamed without the need to remove the entire drill string from the wellbore.

[0538] Cutting structures may be coupled or attached to the drill string using techniques known in the are (for example, by welding). In some embodiments, cutting structures are formed as part of a hinged ring or multi-piece ring that may be bolted, welded, or otherwise attached to the drill string. In some embodiments, the distance that the cutting structures extend beyond the drill string may be adjustable. For example, the cutting element of the cutting structure may include threading and a locking ring that allows for positioning and setting of the cutting element.

[0539] In some wellbores, a wash over or over-coring operation may be needed to free or recover an object in the wellbore that is stuck in the wellbore due to caving, closing, or squeezing of the

formation around the object. The object may be a canister, tool, drill string, or other item. A wash-over pipe with downward facing cutting structures at the bottom of the pipe may be used. The wash over pipe may also include upward facing cutting structures and downward facing cutting structures at locations near the end of the wash-over pipe. The additional upward facing cutting structures and downward facing cutting structures may facilitate freeing and/or recovery of the object stuck in the wellbore. The formation holding the object may be cut away rather than broken by relying on hydraulics and force to break the portion of the formation holding the stuck object.

[0540] A problem in some formations is that the formed borehole begins to close soon after the drill string is removed from the borehole. Boreholes which close up soon after being formed make it difficult to insert objects such as tubulars, canisters, tools, or other equipment into the wellbore. In some embodiments, reaming while drilling applied to the core drill string allows for emplacement of the objects in the center of the core drill pipe. The core drill pipe includes one or more upward facing cutting structures in addition to cutting structures located at the end of the core drill pipe. The core drill pipe may be used to form the wellbore for the object to be inserted in the formation. The object may be positioned in the core of the core drill pipe. Then, the core drill pipe may be removed from the formation. Any parts of the formation that may inhibit removal of the core drill pipe are cut by the upward facing cutting structures as the core drill pipe is removed from the formation.

[0541] Replacement canisters may be positioned in the formation using over core drill pipe. First, the existing canister to be replaced is over cored. The existing canister is then pulled from within the core drill pipe without removing the core drill pipe from the borehole. The replacement canister is then run inside of the core drill pipe. Then, the core drill pipe is removed from the borehole. Upward facing cutting structures positioned along the length of the core drill pipe cut portions of the formation that may inhibit removal of the core drill pipe.

[0542] FIG. 12 depicts a schematic drawing of a drilling system. Pilot bit 432 may form an opening in the formation. Pilot bit 432 may be followed by final diameter bit 434. In some embodiments, pilot bit 432 may be about 2.5 cm in diameter. Pilot bit 432 may be one or more meters below final diameter bit 434. Pilot bit 432 may rotate in a first direction and final diameter bit 434 may rotate in the opposite direction. Counter-rotating bits may allow for the formation of the wellbore along a desired path. Standard mud may be used in both pilot bit 432 and final diameter bit 434. In some embodiments, air or mist may be used as the drilling fluid in one or both bits.

[0543] During some in situ heat treatment processes, wellbores may need to be formed in heated formations. Wellbores drilled into hot formation may be additional or replacement heater wells,

additional or replacement production wells and/or monitor wells. In some in situ heat treatment processes, a barrier formed around all or a portion of the in situ heat treatment process is formed by freeze wells that form a low temperature zone around the freeze wells. A portion of the cooling capacity of the freeze well equipment may be utilized to cool the equipment needed to drill into the hot formation. Drilling bits may be advanced slowly in hot sections to ensure that the formed wellbore cools sufficiently to preclude drilling problems.

[0544] FIG. 13 depicts a schematic drawing of a system for drilling into a hot formation. Cold mud is introduced to drilling bit 434 through conduit 436. As the bit penetrates into the formation, the mud cools the bit and the surrounding formation. In an embodiment, a pilot hole is formed first and the wellbore is finished with a larger drill bit later. In an embodiment, the finished wellbore is formed without a pilot hole being formed. Well advancement is very slow to ensure sufficient cooling.

[0545] FIG. 14 depicts a schematic drawing of a system for drilling into a hot formation. Mud is introduced through conduit 436. Closed loop system 438 is used to circulate cooling fluid. The cooling fluid cools the drilling mud and the formation as drilling bit 434 slowly penetrates into the formation.

[0546] FIG. 15 depicts a schematic drawing of a system for drilling into a hot formation. Mud is introduced through conduit 436. Pilot bit 432 is followed by final diameter bit 434. Closed loop system 438 is used to circulate cooling fluid. The cooling fluid cools the drilling mud supplied to the drill bits. The cooled drilling mud cools the formation.

[0547] In some embodiments, one or more portions of a wellbore may need to be isolated from other portions of the wellbore to establish zonal isolation. In some embodiments, an expandable may be positioned in the wellbore adjacent to a section of the wellbore that is to be isolated. A pig or hydraulic pressure may be used to enlarge the expandable to establish zonal isolation.

[0548] In some embodiments, pathways may be formed in the formation after the wellbores are formed. Pathways may be formed adjacent to heater wellbores and/or adjacent to production wellbores. The pathways may promote better fluid flow and/or better heat conduction. In some embodiments, pathways are formed by hydraulically fracturing the formation. Other fracturing techniques may also be used. In some embodiments, small diameter bores may be formed in the formation. In some embodiments, heating the formation may expand and close or substantially close the fractures or bores formed in the formation. The fractures or holes may extend when the formation is heated. The presence of fractures of holes may increase heat conduction in the formation.

[0549] Some wellbores formed in the formation may be used to facilitate formation of a perimeter barrier around a treatment area. Heat sources in the treatment area may heat

hydrocarbons in the formation within the treatment area. The perimeter barrier may be, but is not limited to, a low temperature or frozen barrier formed by freeze wells, dewatering wells, a grout wall formed in the formation, a sulfur cement barrier, a barrier formed by a gel produced in the formation, a barrier formed by precipitation of salts in the formation, a barrier formed by a polymerization reaction in the formation, and/or sheets driven into the formation. Heat sources, production wells, injection wells, dewatering wells, and/or monitoring wells may be installed in the treatment area defined by the barrier prior to, simultaneously with, or after installation of the barrier.

[0550] A low temperature zone around at least a portion of a treatment area may be formed by freeze wells. In an embodiment, refrigerant is circulated through freeze wells to form low temperature zones around each freeze well. The freeze wells are placed in the formation so that the low temperature zones overlap and form a low temperature zone around the treatment area. The low temperature zone established by freeze wells is maintained below the freezing temperature of aqueous fluid in the formation. Aqueous fluid entering the low temperature zone freezes and forms the frozen barrier. In other embodiments, the freeze barrier is formed by batch operated freeze wells. A cold fluid, such as liquid nitrogen, is introduced into the freeze wells to form low temperature zones around the freeze wells. The fluid is replenished as needed.

[0551] In some embodiments, two or more rows of freeze wells are located about all or a portion of the perimeter of the treatment area to form a thick interconnected low temperature zone. Thick low temperature zones may be formed adjacent to areas in the formation where there is a high flow rate of aqueous fluid in the formation. The thick barrier may ensure that breakthrough of the frozen barrier established by the freeze wells does not occur.

[0552] In some embodiments, a double barrier system is used to isolate a treatment area. The double barrier system may be formed with a first barrier and a second barrier. The first barrier may be formed around at least a portion of the treatment area to inhibit fluid from entering or exiting the treatment area. The second barrier may be formed around at least a portion of the first barrier to isolate an inter-barrier zone between the first barrier and the second barrier. The inter-barrier zone may have a thickness from about 1 m to about 300 m. In some embodiments, the thickness of the inter-barrier zone is from about 10 m to about 100 m, or from about 20 m to about 50 m.

[0553] The double barrier system may allow greater project depths than a single barrier system. Greater depths are possible with the double barrier system because the stepped differential pressures across the first barrier and the second barrier is less than the differential pressure across a single barrier. The smaller differential pressures across the first barrier and the second barrier

make a breach of the double barrier system less likely to occur at depth for the double barrier system as compared to the single barrier system.

[0554] The double barrier system reduces the probability that a barrier breach will affect the treatment area or the formation on the outside of the double barrier. That is, the probability that the location and/or time of occurrence of the breach in the first barrier will coincide with the location and/or time of occurrence of the breach in the second barrier is low, especially if the distance between the first barrier and the second barrier is relatively large (for example, greater than about 15 m). Having a double barrier may reduce or eliminate influx of fluid into the treatment area following a breach of the first barrier or the second barrier. The treatment area may not be affected if the second barrier breaches. If the first barrier breaches, only a portion of the fluid in the inter-barrier zone is able to enter the contained zone. Also, fluid from the contained zone will not pass the second barrier. Recovery from a breach of a barrier of the double barrier system may require less time and fewer resources than recovery from a breach of a single barrier system. For example, reheating a treatment area zone following a breach of a double barrier system may require less energy than reheating a similarly sized treatment area zone following a breach of a single barrier system.

[0555] The first barrier and the second barrier may be the same type of barrier or different types of barriers. In some embodiments, the first barrier and the second barrier are formed by freeze wells. In some embodiments, the first barrier is formed by freeze wells, and the second barrier is a grout wall. The grout wall may be formed of cement, sulfur, sulfur cement, or combinations thereof. In some embodiments, a portion of the first barrier and/or a portion of the second barrier is a natural barrier, such as an impermeable rock formation.

[0556] Vertically positioned freeze wells and/or horizontally positioned freeze wells may be positioned around sides of the treatment area. If the upper layer (the overburden) or the lower layer (the underburden) of the formation is likely to allow fluid flow into the treatment area or out of the treatment area, horizontally positioned freeze wells may be used to form an upper and/or a lower barrier for the treatment area. In some embodiments, an upper barrier and/or a lower barrier may not be necessary if the upper layer and/or the lower layer are at least substantially impermeable. If the upper freeze barrier is formed, portions of heat sources, production wells, injection wells, and/or dewatering wells that pass through the low temperature zone created by the freeze wells forming the upper freeze barrier wells may be insulated and/or heat traced so that the low temperature zone does not adversely affect the functioning of the heat sources, production wells, injection wells and/or dewatering wells passing through the low temperature zone.

[0557] Spacing between adjacent freeze wells may be a function of a number of different factors. The factors may include, but are not limited to, physical properties of formation material, type of refrigeration system, coldness and thermal properties of the refrigerant, flow rate of material into or out of the treatment area, time for forming the low temperature zone, and economic considerations. Consolidated or partially consolidated formation material may allow for a large separation distance between freeze wells. A separation distance between freeze wells in consolidated or partially consolidated formation material may be from about 3 m to about 20 m, about 4 m to about 15 m, or about 5 m to about 10 m. In an embodiment, the spacing between adjacent freeze wells is about 5 m. Spacing between freeze wells in unconsolidated or substantially unconsolidated formation material, such as in tar sand, may need to be smaller than spacing in consolidated formation material. A separation distance between freeze wells in unconsolidated material may be from about 1 m to about 5 m.

[0558] Freeze wells may be placed in the formation so that there is minimal deviation in orientation of one freeze well relative to an adjacent freeze well. Excessive deviation may create a large separation distance between adjacent freeze wells that may not permit formation of an interconnected low temperature zone between the adjacent freeze wells. Factors that influence the manner in which freeze wells are inserted into the ground include, but are not limited to, freeze well insertion time, depth that the freeze wells are to be inserted, formation properties, desired well orientation, and economics.

[0559] Relatively low depth wellbores for freeze wells may be impacted and/or vibrationally inserted into some formations. Wellbores for freeze wells may be impacted and/or vibrationally inserted into formations to depths from about 1 m to about 100 m without excessive deviation in orientation of freeze wells relative to adjacent freeze wells in some types of formations.

[0560] Wellbores for freeze wells placed deep in the formation, or wellbores for freeze wells placed in formations with layers that are difficult to impact or vibrate a well through, may be placed in the formation by directional drilling and/or geosteering. Acoustic signals, electrical signals, magnetic signals, and/or other signals produced in a first wellbore may be used to guide directionally drilling of adjacent wellbores so that desired spacing between adjacent wells is maintained. Tight control of the spacing between wellbores for freeze wells is an important factor in minimizing the time for completion of barrier formation.

[0561] In some embodiments, one or more portions of freeze wells may be angled in the formation. The freeze wells may be angled in the formation adjacent to aquifers. In some embodiments, the angled portions are angled outwards from the treatment area. In some embodiments, the angled portions may be angled inwards towards the treatment area. The angled portions of the freeze wells allow extra length of freeze well to be positioned in the aquifer zones.

Also, the angled portions of the freeze wells may reduce the shear load applied to the frozen barrier by water flowing in the aquifer.

[0562] After formation of the wellbore for the freeze well, the wellbore may be backflushed with water adjacent to the part of the formation that is to be reduced in temperature to form a portion of the freeze barrier. The water may displace drilling fluid remaining in the wellbore. The water may displace indigenous gas in cavities adjacent to the formation. In some embodiments, the wellbore is filled with water from a conduit up to the level of the overburden. In some embodiments, the wellbore is backflushed with water in sections. The wellbore maybe treated in sections having lengths of about 6 m, 10 m, 14 m, 17 m, or greater. Pressure of the water in the wellbore is maintained below the fracture pressure of the formation. In some embodiments, the water, or a portion of the water is removed from the wellbore, and a freeze well is placed in the formation.

[0563] FIG. 16 depicts an embodiment of freeze well 440. Freeze well 440 may include canister 442, inlet conduit 444, spacers 446, and wellcap 448. Spacers 446 may position inlet conduit 444 in canister 442 so that an annular space is formed between the canister and the conduit. Spacers 446 may promote turbulent flow of refrigerant in the annular space between inlet conduit 444 and canister 442, but the spacers may also cause a significant fluid pressure drop. Turbulent fluid flow in the annular space may be promoted by roughening the inner surface of canister 442, by roughening the outer surface of inlet conduit 444, and/or by having a small cross-sectional area annular space that allows for high refrigerant velocity in the annular space. In some embodiments, spacers are not used. Wellhead 450 may suspend canister 442 in wellbore 452.

[0564] Formation refrigerant may flow through cold side conduit 454 from a refrigeration unit to inlet conduit 444 of freeze well 440. The formation refrigerant may flow through an annular space between inlet conduit 444 and canister 442 to warm side conduit 456. Heat may transfer from the formation to canister 442 and from the canister to the formation refrigerant in the annular space. Inlet conduit 444 may be insulated to inhibit heat transfer to the formation refrigerant during passage of the formation refrigerant into freeze well 440. In an embodiment, inlet conduit 444 is a high density polyethylene tube. At cold temperatures, some polymers may exhibit a large amount of thermal contraction. For example, a 260 m initial length of polyethylene conduit subjected to a temperature of about -25 °C may contract by 6 m or more. If a high density polyethylene conduit, or other polymer conduit, is used, the large thermal contraction of the material must be taken into account in determining the final depth of the freeze well. For example, the freeze well may be drilled deeper than needed, and the conduit may be allowed to shrink back during use. In some embodiments, inlet conduit 444 is an insulated metal

tube. In some embodiments, the insulation may be a polymer coating, such as, but not limited to, polyvinylchloride, high density polyethylene, and/or polystyrene.

[0565] Freeze well 440 may be introduced into the formation using a coiled tubing rig. In an embodiment, canister 442 and inlet conduit 444 are wound on a single reel. The coiled tubing rig introduces the canister and inlet conduit 444 into the formation. In an embodiment, canister 442 is wound on a first reel and inlet conduit 444 is wound on a second reel. The coiled tubing rig introduces canister 442 into the formation. Then, the coiled tubing rig is used to introduce inlet conduit 444 into the canister. In other embodiments, freeze well is assembled in sections at the wellbore site and introduced into the formation.

[0566] An insulated section of freeze well 440 may be placed adjacent to overburden 458. An uninsulated section of freeze well 440 may be placed adjacent to layer or layers 460 where a low temperature zone is to be formed. In some embodiments, uninsulated sections of the freeze wells may be positioned adjacent only to aquifers or other permeable portions of the formation that would allow fluid to flow into or out of the treatment area. Portions of the formation where uninsulated sections of the freeze wells are to be placed may be determined using analysis of cores and/or logging techniques.

[0567] Various types of refrigeration systems may be used to form a low temperature zone. Determination of an appropriate refrigeration system may be based on many factors, including, but not limited to: a type of freeze well; a distance between adjacent freeze wells; a refrigerant; a time frame in which to form a low temperature zone; a depth of the low temperature zone; a temperature differential to which the refrigerant will be subjected; one or more chemical and/or physical properties of the refrigerant; one or more environmental concerns related to potential refrigerant releases, leaks or spills; one or more economic factors; water flow rate in the formation; composition and/or properties of formation water including the salinity of the formation water; and one or more properties of the formation such as thermal conductivity, thermal diffusivity, and heat capacity.

[0568] A circulated fluid refrigeration system may utilize a liquid refrigerant (formation refrigerant) that is circulated through freeze wells. Some of the desired properties for the formation refrigerant are: low working temperature, low viscosity at and near the working temperature, high density, high specific heat capacity, high thermal conductivity, low cost, low corrosiveness, and low toxicity. A low working temperature of the formation refrigerant allows a large low temperature zone to be established around a freeze well. The low working temperature of formation refrigerant should be about -20 °C or lower. Formation refrigerants having low working temperatures of at least -60 °C may include aqua ammonia, potassium formate solutions such as Dynalene® HC-50 (Dynalene® Heat Transfer Fluids (Whitehall, Pennsylvania, U.S.A.))

or FREEZIUM® (Kemira Chemicals (Helsinki, Finland)); silicone heat transfer fluids such as Syltherm XLT® (Dow Corning Corporation (Midland, Michigan, U.S.A.); hydrocarbon refrigerants such as propylene; and chlorofluorocarbons such as R-22. Aqua ammonia is a solution of ammonia and water with a weight percent of ammonia between about 20% and about 40%. Aqua ammonia has several properties and characteristics that make use of aqua ammonia as the formation refrigerant desirable. Such properties and characteristics include, but are not limited to, a very low freezing point, a low viscosity, ready availability, and low cost.

[0569] Formation refrigerant that is capable of being chilled below a freezing temperature of aqueous formation fluid may be used to form the low temperature zone around the treatment area. The following equation (the Sanger equation) may be used to model the time t1 needed to form a frozen barrier of radius R around a freeze well having a surface temperature of Ts:

[0570] (EQN. 2) $$t_1 = \frac{R^2 L_1}{4 k_f v_s}\left(2\ln\frac{R}{r_o} - 1 + \frac{c_{vf} v_s}{L_1}\right)$$

[0571] in which:

[0572] $$L_1 = L\frac{a_r^2 - 1}{2\ln a_r} c_{vu} v_o$$

[0573] $$a_r = \frac{R_A}{R}.$$

[0574] In these equations, k_f is the thermal conductivity of the frozen material; c_{vf} and c_{vu} are the volumetric heat capacity of the frozen and unfrozen material, respectively; r_o is the radius of the freeze well; v_s is the temperature difference between the freeze well surface temperature T_s and the freezing point of water T_o; v_o is the temperature difference between the ambient ground temperature T_g and the freezing point of water T_o; L is the volumetric latent heat of freezing of the formation; R is the radius at the frozen-unfrozen interface; and R_A is a radius at which there is no influence from the refrigeration pipe. The Sanger equation may provide a conservative estimate of the time needed to form a frozen barrier of radius R because the equation does not take into consideration superposition of cooling from other freeze wells. The temperature of the formation refrigerant is an adjustable variable that may significantly affect the spacing between freeze wells.

[0575] EQN. 2 implies that a large low temperature zone may be formed by using a refrigerant having an initial temperature that is very low. The use of formation refrigerant having an initial cold temperature of about -30 °C or lower is desirable. Formation refrigerants having initial temperatures warmer than about -30 °C may also be used, but such formation refrigerants require longer times for the low temperature zones produced by individual freeze wells to connect. In addition, such formation refrigerants may require the use of closer freeze well spacings and/or more freeze wells.

[0576] The physical properties of the material used to construct the freeze wells may be a factor in the determination of the coldest temperature of the formation refrigerant used to form the low temperature zone around the treatment area. Carbon steel may be used as a construction material of freeze wells. ASTM A333 grade 6 steel alloys and ASTM A333 grade 3 steel alloys may be used for low temperature applications. ASTM A333 grade 6 steel alloys typically contain little or no nickel and have a low working temperature limit of about -50 °C. ASTM A333 grade 3 steel alloys typically contain nickel and have a much colder low working temperature limit. The nickel in the ASTM A333 grade 3 alloy adds ductility at cold temperatures, but also significantly raises the cost of the metal. In some embodiments, the coldest temperature of the refrigerant is from about -35 °C to about -55 °C, from about -38 °C to about -47 °C, or from about -40 °C to about -45 °C to allow for the use of ASTM A333 grade 6 steel alloys for construction of canisters for freeze wells. Stainless steels, such as 304 stainless steel, may be used to form freeze wells, but the cost of stainless steel is typically much more than the cost of ASTM A333 grade 6 steel alloy.

[0577] In some embodiments, the metal used to form the canisters of the freeze wells may be provided as pipe. In some embodiments, the metal used to form the canisters of the freeze wells may be provided in sheet form. The sheet metal may be longitudinally welded to form pipe and/or coiled tubing. Forming the canisters from sheet metal may improve the economics of the system by allowing for coiled tubing insulation and by reducing the equipment and manpower needed to form and install the canisters using pipe.

[0578] A refrigeration unit may be used to reduce the temperature of formation refrigerant to the low working temperature. In some embodiments, the refrigeration unit may utilize an ammonia vaporization cycle. Refrigeration units are available from Cool Man Inc. (Milwaukee, Wisconsin, U.S.A.), Gartner Refrigeration & Manufacturing (Minneapolis, Minnesota, U.S.A.), and other suppliers. In some embodiments, a cascading refrigeration system may be utilized with a first stage of ammonia and a second stage of carbon dioxide. The circulating refrigerant through the freeze wells may be 30% by weight ammonia in water (aqua ammonia). Alternatively, a single stage carbon dioxide refrigeration system may be used.

[0579] In some embodiments, refrigeration systems for forming a low temperature barrier for a treatment area may be installed and activated before freeze wells are formed in the formation. As the freeze well wellbores are formed, freeze wells may be installed in the wellbores. Refrigerant may be circulated through the wellbores soon after the freeze well is installed into the wellbore. Limiting the time between wellbore formation and cooling initiation may limit or inhibit cross mixing of formation water between different aquifers.

[0580] Grout may be used in combination with freeze wells to provide a barrier for the in situ heat treatment process. The grout fills cavities (vugs) in the formation and reduces the permeability of the formation. Grout may have higher thermal conductivity than gas and/or formation fluid that fills cavities in the formation. Placing grout in the cavities may allow for faster low temperature zone formation. The grout forms a perpetual barrier in the formation that may strengthen the formation. The use of grout in unconsolidated or substantially unconsolidated formation material may allow for larger well spacing than is possible without the use of grout. The combination of grout and the low temperature zone formed by freeze wells may constitute a double barrier for environmental regulation purposes. In some embodiments, the grout is introduced into the formation as a liquid, and the liquid sets in the formation to form a solid. The grout may be any type of grout, including but not limited to, fine cement, micro fine cement, sulfur, sulfur cement, viscous thermoplastics, and/or waxes. The grout may include surfactants, stabilizers or other chemicals that modify the properties of the grout. For example, the presence of surfactant in the grout may promote entry of the grout into small openings in the formation.

[0581] Grout may be introduced into the formation through freeze well wellbores. The grout may be allowed to set. The integrity of the grout wall may be checked. The integrity of the grout wall may be checked by logging techniques and/or by hydrostatic testing. If the permeability of a grouted section is too high, additional grout may be introduced into the formation through freeze well wellbores. After the permeability of the grouted section is sufficiently reduced, freeze wells may be installed in the freeze well wellbores.

[0582] Grout may be injected into the formation at a pressure that is high, but below the fracture pressure of the formation. In some embodiments, grouting is performed in 16 m increments in the freeze wellbore. Larger or smaller increments may be used if desired. In some embodiments, grout is only applied to certain portions of the formation. For example, grout may be applied to the formation through the freeze wellbore only adjacent to aquifer zones and/or to relatively high permeability zones (for example, zones with a permeability greater than about 0.1 darcy). Applying grout to aquifers may inhibit migration of water from one aquifer to a different aquifer. For grout placed in the formation through freeze well wellbores, the grout may inhibit water migration between aquifers during formation of the low temperature zone. The grout may also inhibit water migration between aquifers when an established low temperature zone is allowed to thaw.

[0583] In some embodiments, the grout used to form a barrier may be fine cement and micro fine cement. Cement may provide structural support in the formation. Fine cement may be ASTM type 3 Portland cement. Fine cement may be less expensive than micro fine cement. In an

embodiment, a freeze wellbore is formed in the formation. Selected portions of the freeze wellbore are grouted using fine cement. Then, micro fine cement is injected into the formation through the freeze wellbore. The fine cement may reduce the permeability down to about 10 millidarcy. The micro fine cement may further reduce the permeability to about 0.1 millidarcy. After the grout is introduced into the formation, a freeze wellbore canister may be inserted into the formation. The process may be repeated for each freeze well that will be used to form the barrier.

[0584] In some embodiments, fine cement is introduced into every other freeze wellbore. Micro fine cement is introduced into the remaining wellbores. For example, grout may be used in a formation with freeze wellbores set at about 5 m spacing. A first wellbore is drilled and fine cement is introduced into the formation through the wellbore. A freeze well canister is positioned in the first wellbore. A second wellbore is drilled 10 m away from the first wellbore. Fine cement is introduced into the formation through the second wellbore. A freeze well canister is positioned in the second wellbore. A third wellbore is drilled between the first wellbore and the second wellbore. In some embodiments, grout from the first and/or second wellbores may be detected in the cuttings of the third wellbore. Micro fine cement is introduced into the formation through the third wellbore. A freeze wellbore canister is positioned in the third wellbore. The same procedure is used to form the remaining freeze wells that will form the barrier around the treatment area.

[0585] In some embodiments, wax may be used to form a grout barrier. Wax barriers may be formed in wet, dry or oil wetted formations. Liquid wax introduced into the formation may permeate into adjacent rock and fractures in the formation. Liquid wax may permeate into rock to fill microscopic as well as macroscopic pores and vugs in the rock. The wax solidifies to form a grout barrier that inhibits fluid flow into or out of a treatment area. A wax grout barrier may provide a minimal amount of structural support in the formation. Molten wax may reduce the strength of poorly consolidated soil by reducing inter-grain friction so that the poorly consolidated soil sloughs or liquefies. Poorly consolidated layers may be consolidated by use of cement or other binding agents before introduction of molten wax.

[0586] The wax of a barrier may be a branched paraffin to, for example, inhibit biological degradation of the wax. The wax may include stabilizers, surfactants or other chemicals that modify the physical and/or chemical properties of the wax. The physical properties may be tailored to meet specific needs. The wax may melt at a relative low temperature (for example, the wax may have a typical melting point of about 52 °C). The temperature at which the wax congeals may be at least 5 °C, 10 °C, 20 °C, or 30 °C above the ambient temperature of the formation prior to any heating of the formation. When molten, the wax may have a relatively

low viscosity (for example, 4 to 10 cp at about 99 °C). The flash point of the wax may be relatively high (for example, the flash point may be over 204 °C). The wax may have a density less than the density of water and may have a heat capacity that is less than half the heat capacity of water. The solid wax may have a low thermal conductivity (for example, about 0.18 W/m °C) so that the solid wax is a thermal insulator. Waxes suitable for forming a barrier are available as WAXFIXTM from Carter Technologies Company (Sugar Land, Texas, U.S.A.).

[0587] In some embodiments, a wax barrier or wax barriers may be used as the barriers for the in situ heat treatment process. In some embodiments, a wax barrier may be used in conjunction with freeze wells that form a low temperature barrier around the treatment area. In some embodiments, the wax barrier is formed and freeze wells are installed in the wellbores used for introducing wax into the formation. In some embodiments, the wax barrier is formed in wellbores offset from the freeze well wellbores. The wax barrier may be on the outside or the inside of the freeze wells. In some embodiments, a wax barrier may be formed on both the inside and outside of the freeze wells. The wax barrier may inhibit water flow in the formation that would inhibit the formation of the low temperature zone by the freeze wells. In some embodiments, a wax barrier is formed in the inter-barrier zone between two freeze barriers of a double barrier system.

[0588] Wellbores may be formed in the formation around the treatment area at a close spacing. In some embodiments, the spacing is from about 1.5 m to about 4 m. Low temperature heaters may be inserted in the wellbores. The heaters may operate at temperatures from about 260 °C to about 320 °C so that the temperature at the formation face is below the pyrolysis temperature of hydrocarbons in the formation. The heaters may be activated to heat the formation until the overlap between two adjacent heaters raises the temperature of the zone between the two heaters above the melting temperature of the wax. Heating the formation to obtain superposition of heat with a temperature above the melting temperature of the wax may take one month, two months, or longer. After heating, the heaters may be turned off. Wax may be introduced into the wellbores to form the barrier. The wax may flow into the formation and fill any fractures and porosity that has been heated. The wax congeals when the wax flows to cold regions beyond the heated circumference. This wax barrier formation method may form a more complete barrier than some other methods of wax barrier formation, but the time for heating may be longer than for some of the other methods. Also, if a low temperature barrier is to be formed with the freeze wells placed in the wellbores used for wax injection, the freeze wells will have to remove the heat supplied to the formation to allow for introduction of the wax. The low temperature barrier may take longer to form.

[0589] In some embodiments, the wax barrier may be formed using a conduit placed in the wellbore. FIG. 17A depicts an embodiment of a system for forming a wax barrier in a formation. Wellbore 452 may extend into one or more layers 460 below overburden 458. Wellbore 452 may be an open wellbore below underburden 458. One or more of the layers 460 may include fracture systems 462. One or more of the layers may be vuggy so that the layer or a portion of the layer has a high porosity. Conduit 464 may be positioned in wellbore 452. In some embodiments, low temperature heater 466 may be strapped or attached to conduit 464. In some embodiments, conduit 464 may be a heater element. Heater 466 may be operated so that the heater does not cause pyrolysis of hydrocarbons adjacent to the heater. At least a portion of wellbore 452 may be filled with fluid. The fluid may be formation fluid or water. Heater 466 may be activated to heat the fluid. A portion of the heated fluid may move outwards from heater 466 into the formation. The heated fluid may be injected into the fractures and permeable vuggy zones. The heated fluid may be injected into the fractures and permeable vuggy zones by introducing heated wax into wellbore 452 in the annular space between conduit 464 and the wellbore. The introduced wax flows to the areas heated by the fluid and congeals when the fluid reaches cold regions not heated by the fluid. The wax fills fracture systems 462 and permeable vuggy pathways heated by the fluid, but the wax may not permeate through a significant portion of the rock matrix as when the hot wax is introduced into a heated formation as described above. The wax flows into fracture systems 462 a sufficient distance to join with wax injected from an adjacent well so that a barrier to fluid flow through the fracture systems forms when the wax congeals. A portion of wax may congeal along the wall of a fracture or a vug without completely blocking the fracture or filling the vug. The congealed wax may act as an insulator and allow additional liquid wax to flow beyond the congealed portion to penetrate deeply into the formation and form blockages to fluid flow when the wax cools below the melting temperature of the wax.

[0590] Wax in the annular space of wellbore 452 between conduit 464 and the formation may be removed through conduit by displacing the wax with water or other fluid. Conduit 464 may be removed and a freeze well may be installed in the wellbore. This method may use less wax than the method described above. The heating of the fluid may be accomplished in less than a week or within a day. The small amount of heat input may allow for quicker formation of a low temperature barrier if freeze wells are to be positioned in the wellbores used to introduce wax into the formation.

[0591] In some embodiments, a heater may be suspended in the well without a conduit that allows for removal of excess wax from the wellbore. The wax may be introduced into the well. After wax introduction, the heater may be removed from the well. In some embodiments, a conduit may be positioned in the wellbore, but a heater may not be coupled to the conduit. Hot

wax may be circulated through the conduit so that the wax enters fractures systems and/or vugs adjacent to the wellbore.

[0592] In some embodiments, wax may be used during the formation of a wellbore to improve inter-zonal isolation and protect a low-pressure zone from inflow from a high-pressure zone. During wellbore formation where a high pressure zone and a low pressure zone are penetrated by a common wellbore, it is possible for the high pressure zone to flow into the low pressure zone and cause an underground blowout. To avoid this, the wellbore may be formed through the first zone. Then, an intermediate casing may be set and cemented through the first zone. Setting casing may be time consuming and expensive. Instead of setting a casing, wax may be used to seal the first zone. The wax may also inhibit or prevent mixing of high salinity brines from lower, high pressure zones with fresher brines in upper, lower pressure zones.

[0593] FIG. 17B depicts wellbore 452 drilled to a first depth in formation 758. After the surface casing for wellbore 452 is set and cemented in place, the wellbore is drilled to the first depth which passes through a permeable zone, such as an aquifer. The permeable zone may be fracture system 462'. In some embodiments, a heater is placed in wellbore 452 to heat the vertical interval of fracture system 462'. In some embodiments, hot fluid is circulated in wellbore 452 to heat the vertical interval of fracture system 462'. After heating, molten wax is pumped down wellbore 452. The molten wax flows a selected distance into fracture system 462' before the wax cools sufficiently to solidify and form a seal. The molten wax is introduced into formation 758 at a pressure below the fracture pressure of the formation. In some embodiments, pressure is maintained on the wellhead until the wax has solidified. In some embodiments, the wax is allowed to cool until the wax in wellbore 452 is almost to the congealing temperature of the wax. The wax in wellbore 452 may then be displaced out of the wellbore. The wax makes the portion of formation 758 near wellbore 452 into a substantially impermeable zone. Wellbore 452 may be drilled to depth through one or more permeable zones that are at higher pressures than the pressure in the first permeable zone, such as fracture system 462". Congealed wax in fracture system 462' may inhibit blowout into the lower pressure zone. FIG. 17C depicts wellbore 452 drilled to depth with congealed wax 492 in formation 758.

[0594] In some embodiments, wax may be used to contain and inhibit migration in a subsurface formation that has liquid hydrocarbon contaminants (for example, compounds such as benzene, toluene, ethylbenzene and xylene) condensed in fractures in the formation. The location of the contaminants may be surrounded with heated wax injection wells. Wax may be introduced into the wells to form an outer wax barrier. The wax injected into the fractures from the wax injection wells may mix with the contaminants. The contaminants may be solubilized into the

wax. When the wax congeals, the contaminants may be permanently contained in the solid wax phase.

[0595] In some embodiments, a composition that includes a cross-linkable polymer may be used with or in addition to a wax. Such composition may be provided to the formation as is described above for the wax. The composition may be configured to react and solidify after a selected time in the formation, thereby allowing the composition to be provided as a liquid to the formation. The cross-linkable polymer may include, for example, acrylates, methacrylates, urethanes, and/or epoxies. A cross-linking initiator may be included in the composition. The composition may also include a cross-linking inhibitor. The cross-linking inhibitor may be configured to degrade while in the formation, thereby allowing the composition to solidify.

[0596] In situ heat treatment processes and solution mining processes may heat the treatment area, remove mass from the treatment area, and greatly increase the permeability of the treatment area. In certain embodiments, the treatment area after being treated may have a permeability of at least 0.1 darcy. In some embodiments, the treatment area after being treated has a permeability of at least 1 darcy, of at least 10 darcy, or of at least 100 darcy. The increased permeability allows the fluid to spread in the formation into fractures, microfractures, and/or pore spaces in the formation. Outside of the treatment area, the permeability may remain at the initial permeability of the formation. The increased permeability allows fluid introduced to flow easily within the formation.

[0597] In certain embodiments, a barrier may be formed in the formation after a solution mining process and/or an in situ heat treatment process by introducing a fluid into the formation. The barrier may inhibit formation fluid from entering the treatment area after the solution mining and/or in situ heat treatment processes have ended. The barrier formed by introducing fluid into the formation may allow for isolation of the treatment area.

[0598] The fluid introduced into the formation to form a barrier may include wax, bitumen, heavy oil, sulfur, polymer, gel, saturated saline solution, and/or one or more reactants that react to form a precipitate, solid or high viscosity fluid in the formation. In some embodiments, bitumen, heavy oil, reactants and/or sulfur used to form the barrier are obtained from treatment facilities associated with the in situ heat treatment process. For example, sulfur may be obtained from a Claus process used to treat produced gases to remove hydrogen sulfide and other sulfur compounds.

[0599] The fluid may be introduced into the formation as a liquid, vapor, or mixed phase fluid. The fluid may be introduced into a portion of the formation that is at an elevated temperature. In some embodiments, the fluid is introduced into the formation through wells located near a perimeter of the treatment area. The fluid may be directed away from the treatment area. The

elevated temperature of the formation maintains or allows the fluid to have a low viscosity so that the fluid moves away from the wells. A portion of the fluid may spread outwards in the formation towards a cooler portion of the formation. The relatively high permeability of the formation allows fluid introduced from one wellbore to spread and mix with fluid introduced from other wellbores. In the cooler portion of the formation, the viscosity of the fluid increases, a portion of the fluid precipitates, and/or the fluid solidifies or thickens so that the fluid forms the barrier to flow of formation fluid into or out of the treatment area.

[0600] In some embodiments, a low temperature barrier formed by freeze wells surrounds all or a portion of the treatment area. As the fluid introduced into the formation approaches the low temperature barrier, the temperature of the formation becomes colder. The colder temperature increases the viscosity of the fluid, enhances precipitation, and/or solidifies the fluid to form the barrier to the flow of formation fluid into or out of the formation. The fluid may remain in the formation as a highly viscous fluid or a solid after the low temperature barrier has dissipated.

[0601] In certain embodiments, saturated saline solution is introduced into the formation. Components in the saturated saline solution may precipitate out of solution when the solution reaches a colder temperature. The solidified particles may form the barrier to the flow of formation fluid into or out of the formation. The solidified components may be substantially insoluble in formation fluid.

[0602] In certain embodiments, brine is introduced into the formation as a reactant. A second reactant, such as carbon dioxide, may be introduced into the formation to react with the brine. The reaction may generate a mineral complex that grows in the formation. The mineral complex may be substantially insoluble to formation fluid. In an embodiment, the brine solution includes a sodium and aluminum solution. The second reactant introduced in the formation is carbon dioxide. The carbon dioxide reacts with the brine solution to produce dawsonite. The minerals may solidify and form the barrier to the flow of formation fluid into or out of the formation.

[0603] In some embodiments, the barrier may be formed around a treatment area using sulfur. Advantageously, elemental sulfur is insoluble in water. Liquid and/or solid sulfur in the formation may form a barrier to formation fluid flow into or out of the treatment area.

[0604] A sulfur barrier may be established in the formation during or before initiation of heating to heat the treatment area of the in situ heat treatment process. In some embodiments, sulfur may be introduced into wellbores in the formation that are located between the treatment area and a first barrier (for example, a low temperature barrier established by freeze wells). The formation adjacent to the wellbores that the sulfur is introduced into may be dewatered. In some embodiments, the formation adjacent to the wellbores that the sulfur is introduced into is heated

to facilitate removal of water and to prepare the wellbores and adjacent formation for the introduction of sulfur. The formation adjacent to the wellbores may be heated to a temperature below the pyrolysis temperature of hydrocarbons in the formation. The formation may be heated so that the temperature of a portion of the formation between two adjacent heaters is influenced by both heaters. In some embodiments, the heat may increase the permeability of the formation so that a first wellbore is in fluid communication with an adjacent wellbore.

[0605] After the formation adjacent to the wellbores is heated, molten sulfur at a temperature below the pyrolysis temperature of hydrocarbons in the formation is introduced into the formation. Over a certain temperature range, the viscosity of molten sulfur increases with increasing temperature. The molten sulfur introduced into the formation may be near the melting temperature of sulfur (about 115 °C) so that the sulfur has a relatively low viscosity (about 4-10 cp). Heaters in the wellbores may be temperature limited heaters with Curie temperatures near the melting temperature of sulfur so that the temperature of the molten sulfur stays relatively constant and below temperatures resulting in the formation of viscous molten sulfur. In some embodiments, the region adjacent to the wellbores may be heated to a temperature above the melting point of sulfur, but below the pyrolysis temperature of hydrocarbons in the formation. The heaters may be turned off and the temperature in the wellbores may be monitored (for example, using a fiber optic temperature monitoring system). When the temperature in the wellbore cools to a temperature near the melting temperature of sulfur, molten sulfur may be introduced into the formation.

[0606] The sulfur introduced into the formation is allowed to flow and diffuse into the formation from the wellbores. As the sulfur enters portions of the formation below the melting temperature, the sulfur solidifies and forms a barrier to fluid flow in the formation. Sulfur may be introduced until the formation is not able to accept additional sulfur. Heating may be stopped, and the formation may be allowed to naturally cool so that the sulfur in the formation solidifies. After introduction of the sulfur, the integrity of the formed barrier may be tested using pulse tests and/or tracer tests.

[0607] A barrier may be formed around the treatment area after the in situ heat treatment process. The sulfur may form a substantially permanent barrier in the formation. In some embodiments, a low temperature barrier formed by freeze wells surrounds the treatment area. Sulfur may be introduced on one or both sides of the low temperature barrier to form a barrier in the formation. The sulfur may be introduced into the formation as vapor or a liquid. As the sulfur approaches the low temperature barrier, the sulfur may condense and/or solidify in the formation to form the barrier.

[0608] In some embodiments, the sulfur may be introduced in the heated portion of the portion. The sulfur may be introduced into the formation through wells located near the perimeter of the treatment area. The temperature of the formation may be hotter than the vaporization temperature of sulfur (about 445 °C). The sulfur may be introduced as a liquid, vapor or mixed phase fluid. If a part of the introduced sulfur is in the liquid phase, the heat of the formation may vaporize the sulfur. The sulfur may flow outwards from the introduction wells towards cooler portions of the formation. The sulfur may condense and/or solidify in the formation to form the barrier.

[0609] In some embodiments, the Claus reaction may be used to form sulfur in the formation after the in situ heat treatment process. The Claus reaction is a gas phase equilibrium reaction. The Claus reaction is:

[0610] (EQN. 3) $4H_2S + 2SO_2 \leftrightarrow 3S_2 + 4H_2O$

[0611] Hydrogen sulfide may be obtained by separating the hydrogen sulfide from the produced fluid of an ongoing in situ heat treatment process. A portion of the hydrogen sulfide may be burned to form the needed sulfur dioxide. Hydrogen sulfide may be introduced into the formation through a number of wells in the formation. Sulfur dioxide may be introduced into the formation through other wells. The wells used for injecting sulfur dioxide or hydrogen sulfide may have been production wells, heater wells, monitor wells or other type of well during the in situ heat treatment process. The wells used for injecting sulfur dioxide or hydrogen sulfide may be near the perimeter of the treatment area. The number of wells may be enough so that the formation in the vicinity of the injection wells does not cool to a point where the sulfur dioxide and the hydrogen sulfide can form sulfur and condense, rather than remain in the vapor phase. The wells used to introduce the sulfur dioxide into the formation may also be near the perimeter of the treatment area. In some embodiments, the hydrogen sulfide and sulfur dioxide may be introduced into the formation through the same wells (for example, through two conduits positioned in the same wellbore). The hydrogen sulfide and the sulfur dioxide may react in the formation to form sulfur and water. The sulfur may flow outwards in the formation and condense and/or solidify to form the barrier in the formation.

[0612] The sulfur barrier may form in the formation beyond the area where hydrocarbons in formation fluid generated by the heat treatment process condense in the formation. Regions near the perimeter of the treated area may be at lower temperatures than the treated area. Sulfur may condense and/or solidify from the vapor phase in these lower temperature regions. Additional hydrogen sulfide, and/or sulfur dioxide may diffuse to these lower temperature regions. Additional sulfur may form by the Claus reaction to maintain an equilibrium concentration of sulfur in the vapor phase. Eventually, a sulfur barrier may form around the treated zone. The

vapor phase in the treated region may remain as an equilibrium mixture of sulfur, hydrogen sulfide, sulfur dioxide, water vapor and other vapor products present or evolving from the formation.

[0613] The conversion to sulfur is favored at lower temperatures, so the conversion of hydrogen sulfide and sulfur dioxide to sulfur may take place a distance away from the wells that introduce the reactants into the formation. The Claus reaction may result in the formation of sulfur where the temperature of the formation is cooler (for example where the temperature of the formation is at temperatures from about 180 °C to about 240 °C).

[0614] A temperature monitoring system may be installed in wellbores of freeze wells and/or in monitor wells adjacent to the freeze wells to monitor the temperature profile of the freeze wells and/or the low temperature zone established by the freeze wells. The monitoring system may be used to monitor progress of low temperature zone formation. The monitoring system may be used to determine the location of high temperature areas, potential breakthrough locations, or breakthrough locations after the low temperature zone has formed. Periodic monitoring of the temperature profile of the freeze wells and/or low temperature zone established by the freeze wells may allow additional cooling to be provided to potential trouble areas before breakthrough occurs. Additional cooling may be provided at or adjacent to breakthroughs and high temperature areas to ensure the integrity of the low temperature zone around the treatment area. Additional cooling may be provided by increasing refrigerant flow through selected freeze wells, installing an additional freeze well or freeze wells, and/or by providing a cryogenic fluid, such as liquid nitrogen, to the high temperature areas. Providing additional cooling to potential problem areas before breakthrough occurs may be more time efficient and cost efficient than sealing a breach, reheating a portion of the treatment area that has been cooled by influx of fluid, and/or remediating an area outside of the breached frozen barrier.

[0615] In some embodiments, a traveling thermocouple may be used to monitor the temperature profile of selected freeze wells or monitor wells. In some embodiments, the temperature monitoring system includes thermocouples placed at discrete locations in the wellbores of the freeze wells, in the freeze wells, and/or in the monitoring wells. In some embodiments, the temperature monitoring system comprises a fiber optic temperature monitoring system.

[0616] Fiber optic temperature monitoring systems are available from Sensornet (London, United Kingdom), Sensa (Houston, Texas, U.S.A.), Luna Energy (Blacksburg, Virginia, U.S.A.), Lios Technology GMBH (Cologne, Germany), Oxford Electronics Ltd. (Hampshire, United Kingdom), and Sabeus Sensor Systems (Calabasas, California, U.S.A.). The fiber optic temperature monitoring system includes a data system and one or more fiber optic cables. The data system includes one or more lasers for sending light to the fiber optic cable; and one or more

computers, software and peripherals for receiving, analyzing, and outputting data. The data system may be coupled to one or more fiber optic cables.

[0617] A single fiber optic cable may be several kilometers long. The fiber optic cable may be installed in many freeze wells and/or monitor wells. In some embodiments, two fiber optic cables may be installed in each freeze well and/or monitor well. The two fiber optic cables may be coupled. Using two fiber optic cables per well allows for compensation due to optical losses that occur in the wells and allows for better accuracy of measured temperature profiles.

[0618] The fiber optic temperature monitoring system may be used to detect the location of a breach or a potential breach in a frozen barrier. The search for potential breaches may be performed at scheduled intervals, for example, every two or three months. To determine the location of the breach or potential breach, flow of formation refrigerant to the freeze wells of interest is stopped. In some embodiments, the flow of formation refrigerant to all of the freeze wells is stopped. The rise in the temperature profiles, as well as the rate of change of the temperature profiles, provided by the fiber optic temperature monitoring system for each freeze well can be used to determine the location of any breaches or hot spots in the low temperature zone maintained by the freeze wells. The temperature profile monitored by the fiber optic temperature monitoring system for the two freeze wells closest to the hot spot or fluid flow will show the quickest and greatest rise in temperature. A temperature change of a few degrees Centigrade in the temperature profiles of the freeze wells closest to a troubled area may be sufficient to isolate the location of the trouble area. The shut down time of flow of circulation fluid in the freeze wells of interest needed to detect breaches, potential breaches, and hot spots may be on the order of a few hours or days, depending on the well spacing and the amount of fluid flow affecting the low temperature zone.

[0619] Fiber optic temperature monitoring systems may also be used to monitor temperatures in heated portions of the formation during in situ heat treatment processes. The fiber of a fiber optic cable used in the heated portion of the formation may be clad with a reflective material to facilitate retention of a signal or signals transmitted down the fiber. In some embodiments, the fiber is clad with gold, copper, nickel, aluminum and/or alloys thereof. The cladding may be formed of a material that is able to withstand chemical and temperature conditions in the heated portion of the formation. For example, gold cladding may allow an optical sensor to be used up to temperatures of 700 °C. In some embodiments, the fiber is clad with aluminum. The fiber may be dipped in or run through a bath of liquid aluminum. The clad fiber may then be allowed to cool to secure the aluminum to the fiber. The gold or aluminum cladding may reduce hydrogen darkening of the optical fiber.

[0620] A potential source of heat loss from the heated formation is due to reflux in wells. Refluxing occurs when vapors condense in a well and flow into a portion of the well adjacent to the heated portion of the formation. Vapors may condense in the well adjacent to the overburden of the formation to form condensed fluid. Condensed fluid flowing into the well adjacent to the heated formation absorbs heat from the formation. Heat absorbed by condensed fluids cools the formation and necessitates additional energy input into the formation to maintain the formation at a desired temperature. Some fluids that condense in the overburden and flow into the portion of the well adjacent to the heated formation may react to produce undesired compounds and/or coke. Inhibiting fluids from refluxing may significantly improve the thermal efficiency of the in situ heat treatment system and/or the quality of the product produced from the in situ heat treatment system.

[0621] For some well embodiments, the portion of the well adjacent to the overburden section of the formation is cemented to the formation. In some well embodiments, the well includes packing material placed near the transition from the heated section of the formation to the overburden. The packing material inhibits formation fluid from passing from the heated section of the formation into the section of the wellbore adjacent to the overburden. Cables, conduits, devices, and/or instruments may pass through the packing material, but the packing material inhibits formation fluid from passing up the wellbore adjacent to the overburden section of the formation.

[0622] In some embodiments, one or more baffle systems may be placed in the wellbores to inhibit reflux. The baffle systems may be obstructions to fluid flow into the heated portion of the formation. In some embodiments, refluxing fluid may revaporize on the baffle system before coming into contact with the heated portion of the formation.

[0623] In some embodiments, a gas may be introduced into the formation through wellbores to inhibit reflux in the wellbores. In some embodiments, gas may be introduced into wellbores that include baffle systems to inhibit reflux of fluid in the wellbores. The gas may be carbon dioxide, methane, nitrogen or other desired gas. In some embodiments, the introduction of gas may be used in conjunction with one or more baffle systems in the wellbores. The introduced gas may enhance heat exchange at the baffle systems to help maintain top portions of the baffle systems colder than the lower portions of the baffle systems.

[0624] The flow of production fluid up the well to the surface is desired for some types of wells, especially for production wells. Flow of production fluid up the well is also desirable for some heater wells that are used to control pressure in the formation. The overburden, or a conduit in the well used to transport formation fluid from the heated portion of the formation to the surface, may be heated to inhibit condensation on or in the conduit. Providing heat in the overburden,

however, may be costly and/or may lead to increased cracking or coking of formation fluid as the formation fluid is being produced from the formation.

[0625] To avoid the need to heat the overburden or to heat the conduit passing through the overburden, one or more diverters may be placed in the wellbore to inhibit fluid from refluxing into the wellbore adjacent to the heated portion of the formation. In some embodiments, the diverter retains fluid above the heated portion of the formation. Fluids retained in the diverter may be removed from the diverter using a pump, gas lifting, and/or other fluid removal technique. In certain embodiments, two or more diverters that retain fluid above the heated portion of the formation may be located in the production well. Two or more diverters provide a simple way of separating initial fractions of condensed fluid produced from the in situ heat treatment system. A pump may be placed in each of the diverters to remove condensed fluid from the diverters.

[0626] In some embodiments, the diverter directs fluid to a sump below the heated portion of the formation. An inlet for a lift system may be located in the sump. In some embodiments, the intake of the lift system is located in casing in the sump. In some embodiments, the intake of the lift system is located in an open wellbore. The sump is below the heated portion of the formation. The intake of the pump may be located 1 m, 5 m, 10 m, 20 m or more below the deepest heater used to heat the heated portion of the formation. The sump may be at a cooler temperature than the heated portion of the formation. The sump may be more than 10 °C, more than 50 °C, more than 75 °C, or more than 100 °C below the temperature of the heated portion of the formation. A portion of the fluid entering the sump may be liquid. A portion of the fluid entering the sump may condense within the sump. The lift system moves the fluid in the sump to the surface.

[0627] Production well lift systems may be used to efficiently transport formation fluid from the bottom of the production wells to the surface. Production well lift systems may provide and maintain the maximum required well drawdown (minimum reservoir producing pressure) and producing rates. The production well lift systems may operate efficiently over a wide range of high temperature/multiphase fluids (gas/vapor/steam/water/hydrocarbon liquids) and production rates expected during the life of a typical project. Production well lift systems may include dual concentric rod pump lift systems, chamber lift systems and other types of lift systems.

[0628] Temperature limited heaters may be in configurations and/or may include materials that provide automatic temperature limiting properties for the heater at certain temperatures. In certain embodiments, ferromagnetic materials are used in temperature limited heaters. Ferromagnetic material may self-limit temperature at or near the Curie temperature of the material and/or the phase transformation temperature range to provide a reduced amount of heat

when a time-varying current is applied to the material. In certain embodiments, the ferromagnetic material self-limits temperature of the temperature limited heater at a selected temperature that is approximately the Curie temperature and/or in the phase transformation temperature range. In certain embodiments, the selected temperature is within about 35 °C, within about 25 °C, within about 20 °C, or within about 10 °C of the Curie temperature and/or the phase transformation temperature range. In certain embodiments, ferromagnetic materials are coupled with other materials (for example, highly conductive materials, high strength materials, corrosion resistant materials, or combinations thereof) to provide various electrical and/or mechanical properties. Some parts of the temperature limited heater may have a lower resistance (caused by different geometries and/or by using different ferromagnetic and/or non-ferromagnetic materials) than other parts of the temperature limited heater. Having parts of the temperature limited heater with various materials and/or dimensions allows for tailoring the desired heat output from each part of the heater.

[0629] Temperature limited heaters may be more reliable than other heaters. Temperature limited heaters may be less apt to break down or fail due to hot spots in the formation. In some embodiments, temperature limited heaters allow for substantially uniform heating of the formation. In some embodiments, temperature limited heaters are able to heat the formation more efficiently by operating at a higher average heat output along the entire length of the heater. The temperature limited heater operates at the higher average heat output along the entire length of the heater because power to the heater does not have to be reduced to the entire heater, as is the case with typical constant wattage heaters, if a temperature along any point of the heater exceeds, or is about to exceed, a maximum operating temperature of the heater. Heat output from portions of a temperature limited heater approaching a Curie temperature and/or the phase transformation temperature range of the heater automatically reduces without controlled adjustment of the time-varying current applied to the heater. The heat output automatically reduces due to changes in electrical properties (for example, electrical resistance) of portions of the temperature limited heater. Thus, more power is supplied by the temperature limited heater during a greater portion of a heating process.

[0630] In certain embodiments, the system including temperature limited heaters initially provides a first heat output and then provides a reduced (second heat output) heat output, near, at, or above the Curie temperature and/or the phase transformation temperature range of an electrically resistive portion of the heater when the temperature limited heater is energized by a time-varying current. The first heat output is the heat output at temperatures below which the temperature limited heater begins to self-limit. In some embodiments, the first heat output is the heat output at a temperature about 50 °C, about 75 °C, about 100 °C, or about 125 °C below the

Curie temperature and/or the phase transformation temperature range of the ferromagnetic material in the temperature limited heater.

[0631] The temperature limited heater may be energized by time-varying current (alternating current or modulated direct current) supplied at the wellhead. The wellhead may include a power source and other components (for example, modulation components, transformers, and/or capacitors) used in supplying power to the temperature limited heater. The temperature limited heater may be one of many heaters used to heat a portion of the formation.

[0632] In certain embodiments, the temperature limited heater includes a conductor that operates as a skin effect or proximity effect heater when time-varying current is applied to the conductor. The skin effect limits the depth of current penetration into the interior of the conductor. For ferromagnetic materials, the skin effect is dominated by the magnetic permeability of the conductor. The relative magnetic permeability of ferromagnetic materials is typically between 10 and 1000 (for example, the relative magnetic permeability of ferromagnetic materials is typically at least 10 and may be at least 50, 100, 500, 1000 or greater). As the temperature of the ferromagnetic material is raised above the Curie temperature, or the phase transformation temperature range, and/or as the applied electrical current is increased, the magnetic permeability of the ferromagnetic material decreases substantially and the skin depth expands rapidly (for example, the skin depth expands as the inverse square root of the magnetic permeability). The reduction in magnetic permeability results in a decrease in the AC or modulated DC resistance of the conductor near, at, or above the Curie temperature, the phase transformation temperature range, and/or as the applied electrical current is increased. When the temperature limited heater is powered by a substantially constant current source, portions of the heater that approach, reach, or are above the Curie temperature and/or the phase transformation temperature range may have reduced heat dissipation. Sections of the temperature limited heater that are not at or near the Curie temperature and/or the phase transformation temperature range may be dominated by skin effect heating that allows the heater to have high heat dissipation due to a higher resistive load.

[0633] Curie temperature heaters have been used in soldering equipment, heaters for medical applications, and heating elements for ovens (for example, pizza ovens). Some of these uses are disclosed in U.S. Patent Nos. 5,579,575 to Lamome et al.; 5,065,501 to Henschen et al.; and 5,512,732 to Yagnik et al. U.S. Patent No. 4,849,611 to Whitney et al. describes a plurality of discrete, spaced-apart heating units including a reactive component, a resistive heating component, and a temperature responsive component.

[0634] An advantage of using the temperature limited heater to heat hydrocarbons in the formation is that the conductor is chosen to have a Curie temperature and/or a phase transformation temperature range in a desired range of temperature operation. Operation within

the desired operating temperature range allows substantial heat injection into the formation while maintaining the temperature of the temperature limited heater, and other equipment, below design limit temperatures. Design limit temperatures are temperatures at which properties such as corrosion, creep, and/or deformation are adversely affected. The temperature limiting properties of the temperature limited heater inhibit overheating or burnout of the heater adjacent to low thermal conductivity "hot spots" in the formation. In some embodiments, the temperature limited heater is able to lower or control heat output and/or withstand heat at temperatures above 25 °C, 37 °C, 100 °C, 250 °C, 500 °C, 700 °C, 800 °C, 900 °C, or higher up to 1131 °C, depending on the materials used in the heater.

[0635] The temperature limited heater allows for more heat injection into the formation than constant wattage heaters because the energy input into the temperature limited heater does not have to be limited to accommodate low thermal conductivity regions adjacent to the heater. For example, in Green River oil shale there is a difference of at least a factor of 3 in the thermal conductivity of the lowest richness oil shale layers and the highest richness oil shale layers. When heating such a formation, substantially more heat is transferred to the formation with the temperature limited heater than with the conventional heater that is limited by the temperature at low thermal conductivity layers. The heat output along the entire length of the conventional heater needs to accommodate the low thermal conductivity layers so that the heater does not overheat at the low thermal conductivity layers and burn out. The heat output adjacent to the low thermal conductivity layers that are at high temperature will reduce for the temperature limited heater, but the remaining portions of the temperature limited heater that are not at high temperature will still provide high heat output. Because heaters for heating hydrocarbon formations typically have long lengths (for example, at least 10 m, 100 m, 300 m, 500 m, 1 km or more up to about 10 km), the majority of the length of the temperature limited heater may be operating below the Curie temperature and/or the phase transformation temperature range while only a few portions are at or near the Curie temperature and/or the phase transformation temperature range of the temperature limited heater.

[0636] The use of temperature limited heaters allows for efficient transfer of heat to the formation. Efficient transfer of heat allows for reduction in time needed to heat the formation to a desired temperature. For example, in Green River oil shale, pyrolysis typically requires 9.5 years to 10 years of heating when using a 12 m heater well spacing with conventional constant wattage heaters. For the same heater spacing, temperature limited heaters may allow a larger average heat output while maintaining heater equipment temperatures below equipment design limit temperatures. Pyrolysis in the formation may occur at an earlier time with the larger average heat output provided by temperature limited heaters than the lower average heat output

provided by constant wattage heaters. For example, in Green River oil shale, pyrolysis may occur in 5 years using temperature limited heaters with a 12 m heater well spacing. Temperature limited heaters counteract hot spots due to inaccurate well spacing or drilling where heater wells come too close together. In certain embodiments, temperature limited heaters allow for increased power output over time for heater wells that have been spaced too far apart, or limit power output for heater wells that are spaced too close together. Temperature limited heaters also supply more power in regions adjacent the overburden and underburden to compensate for temperature losses in these regions.

[0637] Temperature limited heaters may be advantageously used in many types of formations. For example, in tar sands formations or relatively permeable formations containing heavy hydrocarbons, temperature limited heaters may be used to provide a controllable low temperature output for reducing the viscosity of fluids, mobilizing fluids, and/or enhancing the radial flow of fluids at or near the wellbore or in the formation. Temperature limited heaters may be used to inhibit excess coke formation due to overheating of the near wellbore region of the formation.

[0638] The use of temperature limited heaters, in some embodiments, eliminates or reduces the need for expensive temperature control circuitry. For example, the use of temperature limited heaters eliminates or reduces the need to perform temperature logging and/or the need to use fixed thermocouples on the heaters to monitor potential overheating at hot spots.

[0639] In certain embodiments, phase transformation (for example, crystalline phase transformation or a change in the crystal structure) of materials used in a temperature limited heater change the selected temperature at which the heater self-limits. Ferromagnetic material used in the temperature limited heater may have a phase transformation (for example, a transformation from ferrite to austenite) that decreases the magnetic permeability of the ferromagnetic material. This reduction in magnetic permeability is similar to reduction in magnetic permeability due to the magnetic transition of the ferromagnetic material at the Curie temperature. The Curie temperature is the magnetic transition temperature of the ferrite phase of the ferromagnetic material. The reduction in magnetic permeability results in a decrease in the AC or modulated DC resistance of the temperature limited heater near, at, or above the temperature of the phase transformation and/or the Curie temperature of the ferromagnetic material.

[0640] The phase transformation of the ferromagnetic material may occur over a temperature range. The temperature range of the phase transformation depends on the ferromagnetic material and may vary, for example, over a range of about 5 °C to a range of about 200 °C. Because the phase transformation takes place over a temperature range, the reduction in the magnetic permeability due to the phase transformation takes place over the temperature range. The

reduction in magnetic permeability may also occur hysteretically over the temperature range of the phase transformation. In some embodiments, the phase transformation back to the lower temperature phase of the ferromagnetic material is slower than the phase transformation to the higher temperature phase (for example, the transition from austenite back to ferrite is slower than the transition from ferrite to austenite). The slower phase transformation back to the lower temperature phase may cause hysteretic operation of the heater at or near the phase transformation temperature range that allows the heater to slowly increase to higher resistance after the resistance of the heater reduces due to high temperature.

[0641] In some embodiments, the phase transformation temperature range overlaps with the reduction in the magnetic permeability when the temperature approaches the Curie temperature of the ferromagnetic material. The overlap may produce a faster drop in electrical resistance versus temperature than if the reduction in magnetic permeability is solely due to the temperature approaching the Curie temperature. The overlap may also produce hysteretic behavior of the temperature limited heater near the Curie temperature and/or in the phase transformation temperature range.

[0642] In certain embodiments, the hysteretic operation due to the phase transformation is a smoother transition than the reduction in magnetic permeability due to magnetic transition at the Curie temperature. The smoother transition may be easier to control (for example, electrical control using a process control device that interacts with the power supply) than the sharper transition at the Curie temperature. In some embodiments, the Curie temperature is located inside the phase transformation range for selected metallurgies used in temperature limited heaters. This phenomenon provides temperature limited heaters with the smooth transition properties of the phase transformation in addition to a sharp and definite transition due to the reduction in magnetic properties at the Curie temperature. Such temperature limited heaters may be easy to control (due to the phase transformation) while providing finite temperature limits (due to the sharp Curie temperature transition). Using the phase transformation temperature range instead of and/or in addition to the Curie temperature in temperature limited heaters increases the number and range of metallurgies that may be used for temperature limited heaters.

[0643] In certain embodiments, alloy additions are made to the ferromagnetic material to adjust the temperature range of the phase transformation. For example, adding carbon to the ferromagnetic material may increase the phase transformation temperature range and lower the onset temperature of the phase transformation. Adding titanium to the ferromagnetic material may increase the onset temperature of the phase transformation and decrease the phase transformation temperature range. Alloy compositions may be adjusted to provide desired Curie temperature and phase transformation properties for the ferromagnetic material. The alloy

composition of the ferromagnetic material may be chosen based on desired properties for the ferromagnetic material (such as, but not limited to, magnetic permeability transition temperature or temperature range, resistance versus temperature profile, or power output). Addition of titanium may allow higher Curie temperatures to be obtained when adding cobalt to 410 stainless steel by raising the ferrite to austenite phase transformation temperature range to a temperature range that is above, or well above, the Curie temperature of the ferromagnetic material.

[0644] In some embodiments, temperature limited heaters are more economical to manufacture or make than standard heaters. Typical ferromagnetic materials include iron, carbon steel, or ferritic stainless steel. Such materials are inexpensive as compared to nickel-based heating alloys (such as nichrome, Kanthal™ (Bulten-Kanthal AB, Sweden), and/or LOHM™ (Driver-Harris Company, Harrison, New Jersey, U.S.A.)) typically used in insulated conductor (mineral insulated cable) heaters. In one embodiment of the temperature limited heater, the temperature limited heater is manufactured in continuous lengths as an insulated conductor heater to lower costs and improve reliability.

[0645] In some embodiments, the temperature limited heater is placed in the heater well using a coiled tubing rig. A heater that can be coiled on a spool may be manufactured by using metal such as ferritic stainless steel (for example, 409 stainless steel) that is welded using electrical resistance welding (ERW). U.S. Patent 7,032,809 to Hopkins describes forming seam-welded pipe. To form a heater section, a metal strip from a roll is passed through a former where it is shaped into a tubular and then longitudinally welded using ERW.

[0646] FIG. 18 depicts an embodiment of a device for longitudinal welding (seam-welding) of a tubular using ERW. Metal strip 474 is shaped into tubular form as it passes through ERW coil 476. Metal strip 474 is then welded into a tubular inside shield 478. As metal strip 474 is joined inside shield 478, inert gas (for example, argon or another suitable welding gas) is provided inside the forming tubular by gas inlets 480. Flushing the tubular with inert gas inhibits oxidation of the tubular as it is formed. Shield 478 may have window 482. Window 482 allows an operator to visually inspect the welding process. Tubular 484 is formed by the welding process.

[0647] In some embodiments, a composite tubular may be formed from the seam-welded tubular. The seam-welded tubular is passed through a second former where a conductive strip (for example, a copper strip) is applied, drawn down tightly on the tubular through a die, and longitudinally welded using ERW. A sheath may be formed by longitudinally welding a support material (for example, steel such as 347H or 347HH) over the conductive strip material. The support material may be a strip rolled over the conductive strip material. An overburden section of the heater may be formed in a similar manner.

[0648] In certain embodiments, the overburden section uses a non-ferromagnetic material such as 304 stainless steel or 316 stainless steel instead of a ferromagnetic material. The heater section and overburden section may be coupled using standard techniques such as butt welding using an orbital welder. In some embodiments, the overburden section material (the non-ferromagnetic material) may be pre-welded to the ferromagnetic material before rolling. The pre-welding may eliminate the need for a separate coupling step (for example, butt welding). In an embodiment, a flexible cable (for example, a furnace cable such as a MGT 1000 furnace cable) may be pulled through the center after forming the tubular heater. An end bushing on the flexible cable may be welded to the tubular heater to provide an electrical current return path. The tubular heater, including the flexible cable, may be coiled onto a spool before installation into a heater well. In an embodiment, the temperature limited heater is installed using the coiled tubing rig. The coiled tubing rig may place the temperature limited heater in a deformation resistant container in the formation. The deformation resistant container may be placed in the heater well using conventional methods.

[0649] Temperature limited heaters may be used for heating hydrocarbon formations including, but not limited to, oil shale formations, coal formations, tar sands formations, and formations with heavy viscous oils. Temperature limited heaters may also be used in the field of environmental remediation to vaporize or destroy soil contaminants. Embodiments of temperature limited heaters may be used to heat fluids in a wellbore or sub-sea pipeline to inhibit deposition of paraffin or various hydrates. In some embodiments, a temperature limited heater is used for solution mining a subsurface formation (for example, an oil shale or a coal formation). In certain embodiments, a fluid (for example, molten salt) is placed in a wellbore and heated with a temperature limited heater to inhibit deformation and/or collapse of the wellbore. In some embodiments, the temperature limited heater is attached to a sucker rod in the wellbore or is part of the sucker rod itself. In some embodiments, temperature limited heaters are used to heat a near wellbore region to reduce near wellbore oil viscosity during production of high viscosity crude oils and during transport of high viscosity oils to the surface. In some embodiments, a temperature limited heater enables gas lifting of a viscous oil by lowering the viscosity of the oil without coking the oil. Temperature limited heaters may be used in sulfur transfer lines to maintain temperatures between about 110 °C and about 130 °C.

[0650] The ferromagnetic alloy or ferromagnetic alloys used in the temperature limited heater determine the Curie temperature of the heater. Curie temperature data for various metals is listed in "American Institute of Physics Handbook," Second Edition, McGraw-Hill, pages 5-170 through 5-176. Ferromagnetic conductors may include one or more of the ferromagnetic elements (iron, cobalt, and nickel) and/or alloys of these elements. In some embodiments,

ferromagnetic conductors include iron-chromium (Fe-Cr) alloys that contain tungsten (W) (for example, HCM12A and SAVE12 (Sumitomo Metals Co., Japan) and/or iron alloys that contain chromium (for example, Fe-Cr alloys, Fe-Cr-W alloys, Fe-Cr-V (vanadium) alloys, and Fe-Cr-Nb (Niobium) alloys). Of the three main ferromagnetic elements, iron has a Curie temperature of approximately 770 °C; cobalt (Co) has a Curie temperature of approximately 1131 °C; and nickel has a Curie temperature of approximately 358 °C. An iron-cobalt alloy has a Curie temperature higher than the Curie temperature of iron. For example, iron-cobalt alloy with 2% by weight cobalt has a Curie temperature of approximately 800 °C; iron-cobalt alloy with 12% by weight cobalt has a Curie temperature of approximately 900 °C; and iron-cobalt alloy with 20% by weight cobalt has a Curie temperature of approximately 950 °C. Iron-nickel alloy has a Curie temperature lower than the Curie temperature of iron. For example, iron-nickel alloy with 20% by weight nickel has a Curie temperature of approximately 720 °C, and iron-nickel alloy with 60% by weight nickel has a Curie temperature of approximately 560 °C.

[0651] Some non-ferromagnetic elements used as alloys raise the Curie temperature of iron. For example, an iron-vanadium alloy with 5.9% by weight vanadium has a Curie temperature of approximately 815 °C. Other non-ferromagnetic elements (for example, carbon, aluminum, copper, silicon, and/or chromium) may be alloyed with iron or other ferromagnetic materials to lower the Curie temperature. Non-ferromagnetic materials that raise the Curie temperature may be combined with non-ferromagnetic materials that lower the Curie temperature and alloyed with iron or other ferromagnetic materials to produce a material with a desired Curie temperature and other desired physical and/or chemical properties. In some embodiments, the Curie temperature material is a ferrite such as NiFe2O4. In other embodiments, the Curie temperature material is a binary compound such as FeNi3 or Fe3Al.

[0652] In some embodiments, the improved alloy includes carbon, cobalt, iron, manganese, silicon, or mixtures thereof. In certain embodiments, the improved alloy includes, by weight: about 0.1% to about 10% cobalt; about 0.1% carbon, about 0.5% manganese, about 0.5% silicon, with the balance being iron. In certain embodiments, the improved alloy includes, by weight: about 0.1% to about 10% cobalt; about 0.1% carbon, about 0.5% manganese, about 0.5% silicon, with the balance being iron.

[0653] In some embodiments, the improved alloy includes chromium, carbon, cobalt, iron, manganese, silicon, titanium, vanadium, or mixtures thereof. In certain embodiments, the improved alloy includes, by weight: about 5% to about 20% cobalt, about 0.1% carbon, about 0.5% manganese, about 0.5% silicon, about 0.1% to about 2% vanadium with the balance being iron. In some embodiments, the improved alloy includes, by weight: about 12% chromium, about 0.1% carbon, about 0.5% silicon, about 0.1% to about 0.5% manganese, above 0% to about

15% cobalt, above 0% to about 2% vanadium, above 0% to about 1% titanium, with the balance being iron. In some embodiments, the improved alloy includes, by weight: about 12% chromium, about 0.1% carbon, about 0.5% silicon, about 0.1% to about 0.5% manganese, above 0% to about 2% vanadium, above 0% to about 1% titanium, with the balance being iron. In some embodiments, the improved alloy includes, by weight: about 12% chromium, about 0.1% carbon, about 0.5% silicon, about 0.1% to about 0.5% manganese, above 0% to about 2% vanadium, with the balance being iron. In certain embodiments, the improved alloy includes, by weight: about 12% chromium, about 0.1% carbon, about 0.5% silicon, about 0.1% to about 0.5% manganese, above 0% to about 15% cobalt, above 0% to about 1% titanium, with the balance being iron. In certain embodiments, the improved alloy includes, by weight: about 12% chromium, about 0.1% carbon, about 0.5% silicon, about 0.1% to about 0.5% manganese, above 0% to about 15% cobalt, with the balance being iron. The addition of vanadium may allow for use of higher amounts of cobalt in the improved alloy.

[0654] Certain embodiments of temperature limited heaters may include more than one ferromagnetic material. Such embodiments are within the scope of embodiments described herein if any conditions described herein apply to at least one of the ferromagnetic materials in the temperature limited heater.

[0655] Ferromagnetic properties generally decay as the Curie temperature and/or the phase transformation temperature range is approached. The "Handbook of Electrical Heating for Industry" by C. James Erickson (IEEE Press, 1995) shows a typical curve for 1% carbon steel (steel with 1% carbon by weight). The loss of magnetic permeability starts at temperatures above 650 °C and tends to be complete when temperatures exceed 730 °C. Thus, the self-limiting temperature may be somewhat below the actual Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. The skin depth for current flow in 1% carbon steel is 0.132 cm at room temperature and increases to 0.445 cm at 720 °C. From 720 °C to 730 °C, the skin depth sharply increases to over 2.5 cm. Thus, a temperature limited heater embodiment using 1% carbon steel begins to self-limit between 650 °C and 730 °C.

[0656] Skin depth generally defines an effective penetration depth of time-varying current into the conductive material. In general, current density decreases exponentially with distance from an outer surface to the center along the radius of the conductor. The depth at which the current density is approximately 1/e of the surface current density is called the skin depth. For a solid cylindrical rod with a diameter much greater than the penetration depth, or for hollow cylinders with a wall thickness exceeding the penetration depth, the skin depth, δ, is:

[0657] (EQN. 4) $\delta = 1981.5 * (\rho/(\mu * f))^{1/2}$;

[0658] in which: δ = skin depth in inches;

[0659] ρ = resistivity at operating temperature (ohm-cm);

[0660] μ = relative magnetic permeability; and

[0661] f = frequency (Hz).

[0662] EQN. 4 is obtained from "Handbook of Electrical Heating for Industry" by C. James Erickson (IEEE Press, 1995). For most metals, resistivity (ρ) increases with temperature. The relative magnetic permeability generally varies with temperature and with current. Additional equations may be used to assess the variance of magnetic permeability and/or skin depth on both temperature and/or current. The dependence of μ on current arises from the dependence of μ on the electromagnetic field.

[0663] Materials used in the temperature limited heater may be selected to provide a desired turndown ratio. Turndown ratios of at least 1.1:1, 2:1, 3:1, 4:1, 5:1, 10:1, 30:1, or 50:1 may be selected for temperature limited heaters. Larger turndown ratios may also be used. A selected turndown ratio may depend on a number of factors including, but not limited to, the type of formation in which the temperature limited heater is located (for example, a higher turndown ratio may be used for an oil shale formation with large variations in thermal conductivity between rich and lean oil shale layers) and/or a temperature limit of materials used in the wellbore (for example, temperature limits of heater materials). In some embodiments, the turndown ratio is increased by coupling additional copper or another good electrical conductor to the ferromagnetic material (for example, adding copper to lower the resistance above the Curie temperature and/or the phase transformation temperature range).

[0664] The temperature limited heater may provide a maximum heat output (power output) below the Curie temperature and/or the phase transformation temperature range of the heater. In certain embodiments, the maximum heat output is at least 400 W/m (Watts per meter), 600 W/m, 700 W/m, 800 W/m, or higher up to 2000 W/m. The temperature limited heater reduces the amount of heat output by a section of the heater when the temperature of the section of the heater approaches or is above the Curie temperature and/or the phase transformation temperature range. The reduced amount of heat may be substantially less than the heat output below the Curie temperature and/or the phase transformation temperature range. In some embodiments, the reduced amount of heat is at most 400 W/m, 200 W/m, 100 W/m or may approach 0 W/m.

[0665] In certain embodiments, the temperature limited heater operates substantially independently of the thermal load on the heater in a certain operating temperature range. "Thermal load" is the rate that heat is transferred from a heating system to its surroundings. It is to be understood that the thermal load may vary with temperature of the surroundings and/or the thermal conductivity of the surroundings. In an embodiment, the temperature limited heater

operates at or above the Curie temperature and/or the phase transformation temperature range of the temperature limited heater such that the operating temperature of the heater increases at most by 3 °C, 2 °C, 1.5 °C, 1 °C, or 0.5 °C for a decrease in thermal load of 1 W/m proximate to a portion of the heater. In certain embodiments, the temperature limited heater operates in such a manner at a relatively constant current.

[0666] The AC or modulated DC resistance and/or the heat output of the temperature limited heater may decrease as the temperature approaches the Curie temperature and/or the phase transformation temperature range and decrease sharply near or above the Curie temperature due to the Curie effect and/or phase transformation effect. In certain embodiments, the value of the electrical resistance or heat output above or near the Curie temperature and/or the phase transformation temperature range is at most one-half of the value of electrical resistance or heat output at a certain point below the Curie temperature and/or the phase transformation temperature range. In some embodiments, the heat output above or near the Curie temperature and/or the phase transformation temperature range is at most 90%, 70%, 50%, 30%, 20%, 10%, or less (down to 1%) of the heat output at a certain point below the Curie temperature and/or the phase transformation temperature range (for example, 30 °C below the Curie temperature, 40 °C below the Curie temperature, 50 °C below the Curie temperature, or 100 °C below the Curie temperature). In certain embodiments, the electrical resistance above or near the Curie temperature and/or the phase transformation temperature range decreases to 80%, 70%, 60%, 50%, or less (down to 1%) of the electrical resistance at a certain point below the Curie temperature and/or the phase transformation temperature range (for example, 30 °C below the Curie temperature, 40 °C below the Curie temperature, 50 °C below the Curie temperature, or 100 °C below the Curie temperature).

[0667] In some embodiments, AC frequency is adjusted to change the skin depth of the ferromagnetic material. For example, the skin depth of 1% carbon steel at room temperature is 0.132 cm at 60 Hz, 0.0762 cm at 180 Hz, and 0.046 cm at 440 Hz. Since heater diameter is typically larger than twice the skin depth, using a higher frequency (and thus a heater with a smaller diameter) reduces heater costs. For a fixed geometry, the higher frequency results in a higher turndown ratio. The turndown ratio at a higher frequency is calculated by multiplying the turndown ratio at a lower frequency by the square root of the higher frequency divided by the lower frequency. In some embodiments, a frequency between 100 Hz and 1000 Hz, between 140 Hz and 200 Hz, or between 400 Hz and 600 Hz is used (for example, 180 Hz, 540 Hz, or 720 Hz). In some embodiments, high frequencies may be used. The frequencies may be greater than 1000 Hz.

[0668] To maintain a substantially constant skin depth until the Curie temperature and/or the phase transformation temperature range of the temperature limited heater is reached, the heater may be operated at a lower frequency when the heater is cold and operated at a higher frequency when the heater is hot. Line frequency heating is generally favorable, however, because there is less need for expensive components such as power supplies, transformers, or current modulators that alter frequency. Line frequency is the frequency of a general supply of current. Line frequency is typically 60 Hz, but may be 50 Hz or another frequency depending on the source for the supply of the current. Higher frequencies may be produced using commercially available equipment such as solid state variable frequency power supplies. Transformers that convert three-phase power to single-phase power with three times the frequency are commercially available. For example, high voltage three-phase power at 60 Hz may be transformed to single-phase power at 180 Hz and at a lower voltage. Such transformers are less expensive and more energy efficient than solid state variable frequency power supplies. In certain embodiments, transformers that convert three-phase power to single-phase power are used to increase the frequency of power supplied to the temperature limited heater.

[0669] In certain embodiments, modulated DC (for example, chopped DC, waveform modulated DC, or cycled DC) may be used for providing electrical power to the temperature limited heater. A DC modulator or DC chopper may be coupled to a DC power supply to provide an output of modulated direct current. In some embodiments, the DC power supply may include means for modulating DC. One example of a DC modulator is a DC-to-DC converter system. DC-to-DC converter systems are generally known in the art. DC is typically modulated or chopped into a desired waveform. Waveforms for DC modulation include, but are not limited to, square-wave, sinusoidal, deformed sinusoidal, deformed square-wave, triangular, and other regular or irregular waveforms.

[0670] The modulated DC waveform generally defines the frequency of the modulated DC. Thus, the modulated DC waveform may be selected to provide a desired modulated DC frequency. The shape and/or the rate of modulation (such as the rate of chopping) of the modulated DC waveform may be varied to vary the modulated DC frequency. DC may be modulated at frequencies that are higher than generally available AC frequencies. For example, modulated DC may be provided at frequencies of at least 1000 Hz. Increasing the frequency of supplied current to higher values advantageously increases the turndown ratio of the temperature limited heater.

[0671] In certain embodiments, the modulated DC waveform is adjusted or altered to vary the modulated DC frequency. The DC modulator may be able to adjust or alter the modulated DC waveform at any time during use of the temperature limited heater and at high currents or

voltages. Thus, modulated DC provided to the temperature limited heater is not limited to a single frequency or even a small set of frequency values. Waveform selection using the DC modulator typically allows for a wide range of modulated DC frequencies and for discrete control of the modulated DC frequency. Thus, the modulated DC frequency is more easily set at a distinct value whereas AC frequency is generally limited to multiples of the line frequency. Discrete control of the modulated DC frequency allows for more selective control over the turndown ratio of the temperature limited heater. Being able to selectively control the turndown ratio of the temperature limited heater allows for a broader range of materials to be used in designing and constructing the temperature limited heater.

[0672] In some embodiments, the modulated DC frequency or the AC frequency is adjusted to compensate for changes in properties (for example, subsurface conditions such as temperature or pressure) of the temperature limited heater during use. The modulated DC frequency or the AC frequency provided to the temperature limited heater is varied based on assessed downhole conditions. For example, as the temperature of the temperature limited heater in the wellbore increases, it may be advantageous to increase the frequency of the current provided to the heater, thus increasing the turndown ratio of the heater. In an embodiment, the downhole temperature of the temperature limited heater in the wellbore is assessed.

[0673] In certain embodiments, the modulated DC frequency, or the AC frequency, is varied to adjust the turndown ratio of the temperature limited heater. The turndown ratio may be adjusted to compensate for hot spots occurring along a length of the temperature limited heater. For example, the turndown ratio is increased because the temperature limited heater is getting too hot in certain locations. In some embodiments, the modulated DC frequency, or the AC frequency, are varied to adjust a turndown ratio without assessing a subsurface condition.

[0674] At or near the Curie temperature and/or the phase transformation temperature range of the ferromagnetic material, a relatively small change in voltage may cause a relatively large change in current to the load. The relatively small change in voltage may produce problems in the power supplied to the temperature limited heater, especially at or near the Curie temperature and/or the phase transformation temperature range. The problems include, but are not limited to, reducing the power factor, tripping a circuit breaker, and/or blowing a fuse. In some cases, voltage changes may be caused by a change in the load of the temperature limited heater. In certain embodiments, an electrical current supply (for example, a supply of modulated DC or AC) provides a relatively constant amount of current that does not substantially vary with changes in load of the temperature limited heater. In an embodiment, the electrical current supply provides an amount of electrical current that remains within 15%, within 10%, within 5%, or within 2% of a selected constant current value when a load of the temperature limited heater changes.

[0675] Temperature limited heaters may generate an inductive load. The inductive load is due to some applied electrical current being used by the ferromagnetic material to generate a magnetic field in addition to generating a resistive heat output. As downhole temperature changes in the temperature limited heater, the inductive load of the heater changes due to changes in the ferromagnetic properties of ferromagnetic materials in the heater with temperature. The inductive load of the temperature limited heater may cause a phase shift between the current and the voltage applied to the heater.

[0676] A reduction in actual power applied to the temperature limited heater may be caused by a time lag in the current waveform (for example, the current has a phase shift relative to the voltage due to an inductive load) and/or by distortions in the current waveform (for example, distortions in the current waveform caused by introduced harmonics due to a non-linear load). Thus, it may take more current to apply a selected amount of power due to phase shifting or waveform distortion. The ratio of actual power applied and the apparent power that would have been transmitted if the same current were in phase and undistorted is the power factor. The power factor is always less than or equal to 1. The power factor is 1 when there is no phase shift or distortion in the waveform.

[0677] Actual power applied to a heater due to a phase shift may be described by EQN. 5:

[0678] (EQN. 5) $P = I \times V \times \cos(\theta)$;

[0679] in which P is the actual power applied to a heater; I is the applied current; V is the applied voltage; and θ is the phase angle difference between voltage and current. Other phenomena such as waveform distortion may contribute to further lowering of the power factor. If there is no distortion in the waveform, then $\cos(\theta)$ is equal to the power factor.

[0680] In certain embodiments, the temperature limited heater includes an inner conductor inside an outer conductor. The inner conductor and the outer conductor are radially disposed about a central axis. The inner and outer conductors may be separated by an insulation layer. In certain embodiments, the inner and outer conductors are coupled at the bottom of the temperature limited heater. Electrical current may flow into the temperature limited heater through the inner conductor and return through the outer conductor. One or both conductors may include ferromagnetic material.

[0681] The insulation layer may comprise an electrically insulating ceramic with high thermal conductivity, such as magnesium oxide, aluminum oxide, silicon dioxide, beryllium oxide, boron nitride, silicon nitride, or combinations thereof. The insulating layer may be a compacted powder (for example, compacted ceramic powder). Compaction may improve thermal conductivity and provide better insulation resistance. For lower temperature applications, polymer insulation made from, for example, fluoropolymers, polyimides, polyamides, and/or

polyethylenes, may be used. In some embodiments, the polymer insulation is made of perfluoroalkoxy (PFA) or polyetheretherketone (PEEK™ (Victrex Ltd, England)). The insulating layer may be chosen to be substantially infrared transparent to aid heat transfer from the inner conductor to the outer conductor. In an embodiment, the insulating layer is transparent quartz sand. The insulation layer may be air or a non-reactive gas such as helium, nitrogen, or sulfur hexafluoride. If the insulation layer is air or a non-reactive gas, there may be insulating spacers designed to inhibit electrical contact between the inner conductor and the outer conductor. The insulating spacers may be made of, for example, high purity aluminum oxide or another thermally conducting, electrically insulating material such as silicon nitride. The insulating spacers may be a fibrous ceramic material such as Nextel™ 312 (3M Corporation, St. Paul, Minnesota, U.S.A.), mica tape, or glass fiber. Ceramic material may be made of alumina, alumina-silicate, alumina-borosilicate, silicon nitride, boron nitride, or other materials.

[0682] The insulation layer may be flexible and/or substantially deformation tolerant. For example, if the insulation layer is a solid or compacted material that substantially fills the space between the inner and outer conductors, the temperature limited heater may be flexible and/or substantially deformation tolerant. Forces on the outer conductor can be transmitted through the insulation layer to the solid inner conductor, which may resist crushing. Such a temperature limited heater may be bent, dog-legged, and spiraled without causing the outer conductor and the inner conductor to electrically short to each other. Deformation tolerance may be important if the wellbore is likely to undergo substantial deformation during heating of the formation.

[0683] In certain embodiments, an outermost layer of the temperature limited heater (for example, the outer conductor) is chosen for corrosion resistance, yield strength, and/or creep resistance. In one embodiment, austenitic (non-ferromagnetic) stainless steels such as 201, 304H, 347H, 347HH, 316H, 310H, 347HP, NF709 (Nippon Steel Corp., Japan) stainless steels, or combinations thereof may be used in the outer conductor. The outermost layer may also include a clad conductor. For example, a corrosion resistant alloy such as 800H or 347H stainless steel may be clad for corrosion protection over a ferromagnetic carbon steel tubular. If high temperature strength is not required, the outermost layer may be constructed from ferromagnetic metal with good corrosion resistance such as one of the ferritic stainless steels. In one embodiment, a ferritic alloy of 82.3% by weight iron with 17.7% by weight chromium (Curie temperature of 678 °C) provides desired corrosion resistance.

[0684] The Metals Handbook, vol. 8, page 291 (American Society of Materials (ASM)) includes a graph of Curie temperature of iron-chromium alloys versus the amount of chromium in the alloys. In some temperature limited heater embodiments, a separate support rod or tubular (made from 347H stainless steel) is coupled to the temperature limited heater made from an iron-

chromium alloy to provide yield strength and/or creep resistance. In certain embodiments, the support material and/or the ferromagnetic material is selected to provide a 100,000 hour creep-rupture strength of at least 20.7 MPa at 650 °C. In some embodiments, the 100,000 hour creep-rupture strength is at least 13.8 MPa at 650 °C or at least 6.9 MPa at 650 °C. For example, 347H steel has a favorable creep-rupture strength at or above 650 °C. In some embodiments, the 100,000 hour creep-rupture strength ranges from 6.9 MPa to 41.3 MPa or more for longer heaters and/or higher earth or fluid stresses.

[0685] In temperature limited heater embodiments with both an inner ferromagnetic conductor and an outer ferromagnetic conductor, the skin effect current path occurs on the outside of the inner conductor and on the inside of the outer conductor. Thus, the outside of the outer conductor may be clad with the corrosion resistant alloy, such as stainless steel, without affecting the skin effect current path on the inside of the outer conductor.

[0686] A ferromagnetic conductor with a thickness of at least the skin depth at the Curie temperature and/or the phase transformation temperature range allows a substantial decrease in resistance of the ferromagnetic material as the skin depth increases sharply near the Curie temperature and/or the phase transformation temperature range. In certain embodiments when the ferromagnetic conductor is not clad with a highly conducting material such as copper, the thickness of the conductor may be 1.5 times the skin depth near the Curie temperature and/or the phase transformation temperature range, 3 times the skin depth near the Curie temperature and/or the phase transformation temperature range, or even 10 or more times the skin depth near the Curie temperature and/or the phase transformation temperature range. If the ferromagnetic conductor is clad with copper, thickness of the ferromagnetic conductor may be substantially the same as the skin depth near the Curie temperature and/or the phase transformation temperature range. In some embodiments, the ferromagnetic conductor clad with copper has a thickness of at least three-fourths of the skin depth near the Curie temperature and/or the phase transformation temperature range.

[0687] In certain embodiments, the temperature limited heater includes a composite conductor with a ferromagnetic tubular and a non-ferromagnetic, high electrical conductivity core. The non-ferromagnetic, high electrical conductivity core reduces a required diameter of the conductor. For example, the conductor may be composite 1.19 cm diameter conductor with a core of 0.575 cm diameter copper clad with a 0.298 cm thickness of ferritic stainless steel or carbon steel surrounding the core. The core or non-ferromagnetic conductor may be copper or copper alloy. The core or non-ferromagnetic conductor may also be made of other metals that exhibit low electrical resistivity and relative magnetic permeabilities near 1 (for example, substantially non-ferromagnetic materials such as aluminum and aluminum alloys, phosphor

bronze, beryllium copper, and/or brass). A composite conductor allows the electrical resistance of the temperature limited heater to decrease more steeply near the Curie temperature and/or the phase transformation temperature range. As the skin depth increases near the Curie temperature and/or the phase transformation temperature range to include the copper core, the electrical resistance decreases very sharply.

[0688] The composite conductor may increase the conductivity of the temperature limited heater and/or allow the heater to operate at lower voltages. In an embodiment, the composite conductor exhibits a relatively flat resistance versus temperature profile at temperatures below a region near the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor of the composite conductor. In some embodiments, the temperature limited heater exhibits a relatively flat resistance versus temperature profile between 100 °C and 750 °C or between 300 °C and 600 °C. The relatively flat resistance versus temperature profile may also be exhibited in other temperature ranges by adjusting, for example, materials and/or the configuration of materials in the temperature limited heater. In certain embodiments, the relative thickness of each material in the composite conductor is selected to produce a desired resistivity versus temperature profile for the temperature limited heater.

[0689] In certain embodiments, the relative thickness of each material in a composite conductor is selected to produce a desired resistivity versus temperature profile for a temperature limited heater. In an embodiment, the composite conductor is an inner conductor surrounded by 0.127 cm thick magnesium oxide powder as an insulator. The outer conductor may be 304H stainless steel with a wall thickness of 0.127 cm. The outside diameter of the heater may be about 1.65 cm.

[0690] A composite conductor (for example, a composite inner conductor or a composite outer conductor) may be manufactured by methods including, but not limited to, coextrusion, roll forming, tight fit tubing (for example, cooling the inner member and heating the outer member, then inserting the inner member in the outer member, followed by a drawing operation and/or allowing the system to cool), explosive or electromagnetic cladding, arc overlay welding, longitudinal strip welding, plasma powder welding, billet coextrusion, electroplating, drawing, sputtering, plasma deposition, coextrusion casting, magnetic forming, molten cylinder casting (of inner core material inside the outer or vice versa), insertion followed by welding or high temperature braising, shielded active gas welding (SAG), and/or insertion of an inner pipe in an outer pipe followed by mechanical expansion of the inner pipe by hydroforming or use of a pig to expand and swage the inner pipe against the outer pipe. In some embodiments, a ferromagnetic conductor is braided over a non-ferromagnetic conductor. In certain embodiments, composite conductors are formed using methods similar to those used for cladding (for example, cladding

copper to steel). A metallurgical bond between copper cladding and base ferromagnetic material may be advantageous. Composite conductors produced by a coextrusion process that forms a good metallurgical bond (for example, a good bond between copper and 446 stainless steel) may be provided by Anomet Products, Inc. (Shrewsbury, Massachusetts, U.S.A.).

[0691] FIGS. 19-40 depict various embodiments of temperature limited heaters. One or more features of an embodiment of the temperature limited heater depicted in any of these figures may be combined with one or more features of other embodiments of temperature limited heaters depicted in these figures. In certain embodiments described herein, temperature limited heaters are dimensioned to operate at a frequency of 60 Hz AC. It is to be understood that dimensions of the temperature limited heater may be adjusted from those described herein to operate in a similar manner at other AC frequencies or with modulated DC current.

[0692] FIG. 19 depicts a cross-sectional representation of an embodiment of the temperature limited heater with an outer conductor having a ferromagnetic section and a non-ferromagnetic section. FIGS. 20 and 21 depict transverse cross-sectional views of the embodiment shown in FIG. 19. In one embodiment, ferromagnetic section 486 is used to provide heat to hydrocarbon layers in the formation. Non-ferromagnetic section 488 is used in the overburden of the formation. Non-ferromagnetic section 488 provides little or no heat to the overburden, thus inhibiting heat losses in the overburden and improving heater efficiency. Ferromagnetic section 486 includes a ferromagnetic material such as 409 stainless steel or 410 stainless steel. Ferromagnetic section 486 has a thickness of 0.3 cm. Non-ferromagnetic section 488 is copper with a thickness of 0.3 cm. Inner conductor 490 is copper. Inner conductor 490 has a diameter of 0.9 cm. Electrical insulator 500 is silicon nitride, boron nitride, magnesium oxide powder, or another suitable insulator material. Electrical insulator 500 has a thickness of 0.1 cm to 0.3 cm.

[0693] FIG. 22 depicts a cross-sectional representation of an embodiment of a temperature limited heater with an outer conductor having a ferromagnetic section and a non-ferromagnetic section placed inside a sheath. FIGS. 23, 24, and 25 depict transverse cross-sectional views of the embodiment shown in FIG. 22. Ferromagnetic section 486 is 410 stainless steel with a thickness of 0.6 cm. Non-ferromagnetic section 488 is copper with a thickness of 0.6 cm. Inner conductor 490 is copper with a diameter of 0.9 cm. Outer conductor 502 includes ferromagnetic material. Outer conductor 502 provides some heat in the overburden section of the heater. Providing some heat in the overburden inhibits condensation or refluxing of fluids in the overburden. Outer conductor 502 is 409, 410, or 446 stainless steel with an outer diameter of 3.0 cm and a thickness of 0.6 cm. Electrical insulator 500 includes compacted magnesium oxide powder with a thickness of 0.3 cm. In some embodiments, electrical insulator 500 includes

silicon nitride, boron nitride, or hexagonal type boron nitride. Conductive section 504 may couple inner conductor 490 with ferromagnetic section 486 and/or outer conductor 502.

[0694] FIG. 26A and FIG. 26B depict cross-sectional representations of an embodiment of a temperature limited heater with a ferromagnetic inner conductor. Inner conductor 490 is a 1" Schedule XXS 446 stainless steel pipe. In some embodiments, inner conductor 490 includes 409 stainless steel, 410 stainless steel, Invar 36, alloy 42-6, alloy 52, or other ferromagnetic materials. Inner conductor 490 has a diameter of 2.5 cm. Electrical insulator 500 includes compacted silicon nitride, boron nitride, or magnesium oxide powders; or polymers, Nextel ceramic fiber, mica, or glass fibers. Outer conductor 502 is copper or any other non-ferromagnetic material, such as but not limited to copper alloys, aluminum and/or aluminum alloys. Outer conductor 502 is coupled to jacket 506. Jacket 506 is 304H, 316H, or 347H stainless steel. In this embodiment, a majority of the heat is produced in inner conductor 490.

[0695] FIG. 27A and FIG. 27B depict cross-sectional representations of an embodiment of a temperature limited heater with a ferromagnetic inner conductor and a non-ferromagnetic core. Inner conductor 490 may be made of 446 stainless steel, 409 stainless steel, 410 stainless steel, carbon steel, Armco ingot iron, iron-cobalt alloys, or other ferromagnetic materials. Core 508 may be tightly bonded inside inner conductor 490. Core 508 is copper or other non-ferromagnetic material. In certain embodiments, core 508 is inserted as a tight fit inside inner conductor 490 before a drawing operation. In some embodiments, core 508 and inner conductor 490 are coextrusion bonded. Outer conductor 502 is 347H stainless steel. A drawing or rolling operation to compact electrical insulator 500 (for example, compacted silicon nitride, boron nitride, or magnesium oxide powder) may ensure good electrical contact between inner conductor 490 and core 508. In this embodiment, heat is produced primarily in inner conductor 490 until the Curie temperature and/or the phase transformation temperature range is approached. Resistance then decreases sharply as current penetrates core 508.

[0696] FIG. 28A and FIG. 28B depict cross-sectional representations of an embodiment of a temperature limited heater with a ferromagnetic outer conductor. Inner conductor 490 is nickel-clad copper. Electrical insulator 500 is silicon nitride, boron nitride, or magnesium oxide. Outer conductor 502 is a 1" Schedule XXS carbon steel pipe. In this embodiment, heat is produced primarily in outer conductor 502, resulting in a small temperature differential across electrical insulator 500.

[0697] FIG. 29A and FIG. 29B depict cross-sectional representations of an embodiment of a temperature limited heater with a ferromagnetic outer conductor that is clad with a corrosion resistant alloy. Inner conductor 490 is copper. Outer conductor 502 is a 1" Schedule XXS carbon steel pipe. Outer conductor 502 is coupled to jacket 506. Jacket 506 is made of corrosion

resistant material (for example, 347H stainless steel). Jacket 506 provides protection from corrosive fluids in the wellbore (for example, sulfidizing and carburizing gases). Heat is produced primarily in outer conductor 502, resulting in a small temperature differential across electrical insulator 500.

[0698] FIG. 30A and FIG. 30B depict cross-sectional representations of an embodiment of a temperature limited heater with a ferromagnetic outer conductor. The outer conductor is clad with a conductive layer and a corrosion resistant alloy. Inner conductor 490 is copper. Electrical insulator 500 is silicon nitride, boron nitride, or magnesium oxide. Outer conductor 502 is a 1" Schedule 80 446 stainless steel pipe. Outer conductor 502 is coupled to jacket 506. Jacket 506 is made from corrosion resistant material such as 347H stainless steel. In an embodiment, conductive layer 510 is placed between outer conductor 502 and jacket 506. Conductive layer 510 is a copper layer. Heat is produced primarily in outer conductor 502, resulting in a small temperature differential across electrical insulator 500. Conductive layer 510 allows a sharp decrease in the resistance of outer conductor 502 as the outer conductor approaches the Curie temperature and/or the phase transformation temperature range. Jacket 506 provides protection from corrosive fluids in the wellbore.

[0699] In some embodiments, the conductor (for example, an inner conductor, an outer conductor, or a ferromagnetic conductor) is the composite conductor that includes two or more different materials. In certain embodiments, the composite conductor includes two or more ferromagnetic materials. In some embodiments, the composite ferromagnetic conductor includes two or more radially disposed materials. In certain embodiments, the composite conductor includes a ferromagnetic conductor and a non-ferromagnetic conductor. In some embodiments, the composite conductor includes the ferromagnetic conductor placed over a non-ferromagnetic core. Two or more materials may be used to obtain a relatively flat electrical resistivity versus temperature profile in a temperature region below the Curie temperature, and/or the phase transformation temperature range, and/or a sharp decrease (a high turndown ratio) in the electrical resistivity at or near the Curie temperature and/or the phase transformation temperature range. In some cases, two or more materials are used to provide more than one Curie temperature and/or phase transformation temperature range for the temperature limited heater.

[0700] The composite electrical conductor may be used as the conductor in any electrical heater embodiment described herein. For example, the composite conductor may be used as the conductor in a conductor-in-conduit heater or an insulated conductor heater. In certain embodiments, the composite conductor may be coupled to a support member such as a support conductor. The support member may be used to provide support to the composite conductor so that the composite conductor is not relied upon for strength at or near the Curie temperature

and/or the phase transformation temperature range. The support member may be useful for heaters of lengths of at least 100 m. The support member may be a non-ferromagnetic member that has good high temperature creep strength. Examples of materials that are used for a support member include, but are not limited to, Haynes® 625 alloy and Haynes® HR120® alloy (Haynes International, Kokomo, Indiana, U.S.A.), NF709, Incoloy® 800H alloy and 347HP alloy (Allegheny Ludlum Corp., Pittsburgh, Pennsylvania, U.S.A.). In some embodiments, materials in a composite conductor are directly coupled (for example, brazed, metallurgically bonded, or swaged) to each other and/or the support member. Using a support member may reduce the need for the ferromagnetic member to provide support for the temperature limited heater, especially at or near the Curie temperature and/or the phase transformation temperature range. Thus, the temperature limited heater may be designed with more flexibility in the selection of ferromagnetic materials.

[0701] FIG. 31 depicts a cross-sectional representation of an embodiment of the composite conductor with the support member. Core 508 is surrounded by ferromagnetic conductor 512 and support member 514. In some embodiments, core 508, ferromagnetic conductor 512, and support member 514 are directly coupled (for example, brazed together or metallurgically bonded together). In one embodiment, core 508 is copper, ferromagnetic conductor 512 is 446 stainless steel, and support member 514 is 347H alloy. In certain embodiments, support member 514 is a Schedule 80 pipe. Support member 514 surrounds the composite conductor having ferromagnetic conductor 512 and core 508. Ferromagnetic conductor 512 and core 508 may be joined to form the composite conductor by, for example, a coextrusion process. For example, the composite conductor is a 1.9 cm outside diameter 446 stainless steel ferromagnetic conductor surrounding a 0.95 cm diameter copper core.

[0702] In certain embodiments, the diameter of core 508 is adjusted relative to a constant outside diameter of ferromagnetic conductor 512 to adjust the turndown ratio of the temperature limited heater. For example, the diameter of core 508 may be increased to 1.14 cm while maintaining the outside diameter of ferromagnetic conductor 512 at 1.9 cm to increase the turndown ratio of the heater.

[0703] In some embodiments, conductors (for example, core 508 and ferromagnetic conductor 512) in the composite conductor are separated by support member 514. FIG. 32 depicts a cross-sectional representation of an embodiment of the composite conductor with support member 514 separating the conductors. In one embodiment, core 508 is copper with a diameter of 0.95 cm, support member 514 is 347H alloy with an outside diameter of 1.9 cm, and ferromagnetic conductor 512 is 446 stainless steel with an outside diameter of 2.7 cm. The support member

depicted in FIG. 32 has a lower creep strength relative to the support members depicted in FIG. 31.

[0704] In certain embodiments, support member 514 is located inside the composite conductor. FIG. 33 depicts a cross-sectional representation of an embodiment of the composite conductor surrounding support member 514. Support member 514 is made of 347H alloy. Inner conductor 490 is copper. Ferromagnetic conductor 512 is 446 stainless steel. In one embodiment, support member 514 is 1.25 cm diameter 347H alloy, inner conductor 490 is 1.9 cm outside diameter copper, and ferromagnetic conductor 512 is 2.7 cm outside diameter 446 stainless steel. The turndown ratio is higher than the turndown ratio for the embodiments depicted in FIGS. 31, 32, and 34 for the same outside diameter, but the creep strength is lower.

[0705] In some embodiments, the thickness of inner conductor 490, which is copper, is reduced and the thickness of support member 514 is increased to increase the creep strength at the expense of reduced turndown ratio. For example, the diameter of support member 514 is increased to 1.6 cm while maintaining the outside diameter of inner conductor 490 at 1.9 cm to reduce the thickness of the conduit. This reduction in thickness of inner conductor 490 results in a decreased turndown ratio relative to the thicker inner conductor embodiment but an increased creep strength.

[0706] In one embodiment, support member 514 is a conduit (or pipe) inside inner conductor 490 and ferromagnetic conductor 512. FIG. 34 depicts a cross-sectional representation of an embodiment of the composite conductor surrounding support member 514. In one embodiment, support member 514 is 347H alloy with a 0.63 cm diameter center hole. In some embodiments, support member 514 is a preformed conduit. In certain embodiments, support member 514 is formed by having a dissolvable material (for example, copper dissolvable by nitric acid) located inside the support member during formation of the composite conductor. The dissolvable material is dissolved to form the hole after the conductor is assembled. In an embodiment, support member 514 is 347H alloy with an inside diameter of 0.63 cm and an outside diameter of 1.6 cm, inner conductor 490 is copper with an outside diameter of 1.8 cm, and ferromagnetic conductor 512 is 446 stainless steel with an outside diameter of 2.7 cm.

[0707] In certain embodiments, the composite electrical conductor is used as the conductor in the conductor-in-conduit heater. For example, the composite electrical conductor may be used as conductor 516 in FIG. 35

[0708] FIG. 35 depicts a cross-sectional representation of an embodiment of the conductor-in-conduit heater. Conductor 516 is disposed in conduit 518. Conductor 516 is a rod or conduit of electrically conductive material. Low resistance sections 520 are present at both ends of conductor 516 to generate less heating in these sections. Low resistance section 520 is formed by

having a greater cross-sectional area of conductor 516 in that section, or the sections are made of material having less resistance. In certain embodiments, low resistance section 520 includes a low resistance conductor coupled to conductor 516.

[0709] Conduit 518 is made of an electrically conductive material. Conduit 518 is disposed in opening 522 in hydrocarbon layer 460. Opening 522 has a diameter that accommodates conduit 518.

[0710] Conductor 516 may be centered in conduit 518 by centralizers 524. Centralizers 524 electrically isolate conductor 516 from conduit 518. Centralizers 524 inhibit movement and properly locate conductor 516 in conduit 518. Centralizers 524 are made of ceramic material or a combination of ceramic and metallic materials. Centralizers 524 inhibit deformation of conductor 516 in conduit 518. Centralizers 524 are touching or spaced at intervals between approximately 0.1 m (meters) and approximately 3 m or more along conductor 516.

[0711] A second low resistance section 520 of conductor 516 may couple conductor 516 to wellhead 450, as depicted in FIG. 35. Electrical current may be applied to conductor 516 from power cable 526 through low resistance section 520 of conductor 516. Electrical current passes from conductor 516 through sliding connector 528 to conduit 518. Conduit 518 may be electrically insulated from overburden casing 530 and from wellhead 450 to return electrical current to power cable 526. Heat may be generated in conductor 516 and conduit 518. The generated heat may radiate in conduit 518 and opening 522 to heat at least a portion of hydrocarbon layer 460.

[0712] Overburden casing 530 may be disposed in overburden 458. Overburden casing 530 is, in some embodiments, surrounded by materials (for example, reinforcing material and/or cement) that inhibit heating of overburden 458. Low resistance section 520 of conductor 516 may be placed in overburden casing 530. Low resistance section 520 of conductor 516 is made of, for example, carbon steel. Low resistance section 520 of conductor 516 may be centralized in overburden casing 530 using centralizers 524. Centralizers 524 are spaced at intervals of approximately 6 m to approximately 12 m or, for example, approximately 9 m along low resistance section 520 of conductor 516. In a heater embodiment, low resistance section 520 of conductor 516 is coupled to conductor 516 by one or more welds. In other heater embodiments, low resistance sections are threaded, threaded and welded, or otherwise coupled to the conductor. Low resistance section 520 generates little or no heat in overburden casing 530. Packing 532 may be placed between overburden casing 530 and opening 522. Packing 532 may be used as a cap at the junction of overburden 458 and hydrocarbon layer 460 to allow filling of materials in the annulus between overburden casing 530 and opening 522. In some embodiments, packing 532 inhibits fluid from flowing from opening 522 to surface 534.

[0713] FIG. 36 depicts a cross-sectional representation of an embodiment of a removable conductor-in-conduit heat source. Conduit 518 may be placed in opening 522 through overburden 458 such that a gap remains between the conduit and overburden casing 530. Fluids may be removed from opening 522 through the gap between conduit 518 and overburden casing 530. Fluids may be removed from the gap through conduit 536. Conduit 518 and components of the heat source included in the conduit that are coupled to wellhead 450 may be removed from opening 522 as a single unit. The heat source may be removed as a single unit to be repaired, replaced, and/or used in another portion of the formation.

[0714] For a temperature limited heater in which the ferromagnetic conductor provides a majority of the resistive heat output below the Curie temperature and/or the phase transformation temperature range, a majority of the current flows through material with highly non-linear functions of magnetic field (H) versus magnetic induction (B). These non-linear functions may cause strong inductive effects and distortion that lead to decreased power factor in the temperature limited heater at temperatures below the Curie temperature and/or the phase transformation temperature range. These effects may render the electrical power supply to the temperature limited heater difficult to control and may result in additional current flow through surface and/or overburden power supply conductors. Expensive and/or difficult to implement control systems such as variable capacitors or modulated power supplies may be used to compensate for these effects and to control temperature limited heaters where the majority of the resistive heat output is provided by current flow through the ferromagnetic material.

[0715] In certain temperature limited heater embodiments, the ferromagnetic conductor confines a majority of the flow of electrical current to an electrical conductor coupled to the ferromagnetic conductor when the temperature limited heater is below or near the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. The electrical conductor may be a sheath, jacket, support member, corrosion resistant member, or other electrically resistive member. In some embodiments, the ferromagnetic conductor confines a majority of the flow of electrical current to the electrical conductor positioned between an outermost layer and the ferromagnetic conductor. The ferromagnetic conductor is located in the cross section of the temperature limited heater such that the magnetic properties of the ferromagnetic conductor at or below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor confine the majority of the flow of electrical current to the electrical conductor. The majority of the flow of electrical current is confined to the electrical conductor due to the skin effect of the ferromagnetic conductor. Thus, the majority of the current is flowing through material with substantially linear resistive properties throughout most of the operating range of the heater.

[0716] In certain embodiments, the ferromagnetic conductor and the electrical conductor are located in the cross section of the temperature limited heater so that the skin effect of the ferromagnetic material limits the penetration depth of electrical current in the electrical conductor and the ferromagnetic conductor at temperatures below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. Thus, the electrical conductor provides a majority of the electrically resistive heat output of the temperature limited heater at temperatures up to a temperature at or near the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. In certain embodiments, the dimensions of the electrical conductor may be chosen to provide desired heat output characteristics.

[0717] Because the majority of the current flows through the electrical conductor below the Curie temperature and/or the phase transformation temperature range, the temperature limited heater has a resistance versus temperature profile that at least partially reflects the resistance versus temperature profile of the material in the electrical conductor. Thus, the resistance versus temperature profile of the temperature limited heater is substantially linear below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor if the material in the electrical conductor has a substantially linear resistance versus temperature profile. For example, the temperature limited heater in which the majority of the current flows in the electrical conductor below the Curie temperature and/or the phase transformation temperature range may have a resistance versus temperature profile similar to the profile shown in FIG. 214. The resistance of the temperature limited heater has little or no dependence on the current flowing through the heater until the temperature nears the Curie temperature and/or the phase transformation temperature range. The majority of the current flows in the electrical conductor rather than the ferromagnetic conductor below the Curie temperature and/or the phase transformation temperature range.

[0718] Resistance versus temperature profiles for temperature limited heaters in which the majority of the current flows in the electrical conductor also tend to exhibit sharper reductions in resistance near or at the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. For example, the reduction in resistance shown in FIG. 214 is sharper than the reduction in resistance shown in FIG. 200. The sharper reductions in resistance near or at the Curie temperature and/or the phase transformation temperature range are easier to control than more gradual resistance reductions near the Curie temperature and/or the phase transformation temperature range because little current is flowing through the ferromagnetic material.

[0719] In certain embodiments, the material and/or the dimensions of the material in the electrical conductor are selected so that the temperature limited heater has a desired resistance

versus temperature profile below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor.

[0720] Temperature limited heaters in which the majority of the current flows in the electrical conductor rather than the ferromagnetic conductor below the Curie temperature and/or the phase transformation temperature range are easier to predict and/or control. Behavior of temperature limited heaters in which the majority of the current flows in the electrical conductor rather than the ferromagnetic conductor below the Curie temperature and/or the phase transformation temperature range may be predicted by, for example, its resistance versus temperature profile and/or its power factor versus temperature profile. Resistance versus temperature profiles and/or power factor versus temperature profiles may be assessed or predicted by, for example, experimental measurements that assess the behavior of the temperature limited heater, analytical equations that assess or predict the behavior of the temperature limited heater, and/or simulations that assess or predict the behavior of the temperature limited heater.

[0721] In certain embodiments, assessed or predicted behavior of the temperature limited heater is used to control the temperature limited heater. The temperature limited heater may be controlled based on measurements (assessments) of the resistance and/or the power factor during operation of the heater. In some embodiments, the power, or current, supplied to the temperature limited heater is controlled based on assessment of the resistance and/or the power factor of the heater during operation of the heater and the comparison of this assessment versus the predicted behavior of the heater. In certain embodiments, the temperature limited heater is controlled without measurement of the temperature of the heater or a temperature near the heater. Controlling the temperature limited heater without temperature measurement eliminates operating costs associated with downhole temperature measurement. Controlling the temperature limited heater based on assessment of the resistance and/or the power factor of the heater also reduces the time for making adjustments in the power or current supplied to the heater compared to controlling the heater based on measured temperature.

[0722] As the temperature of the temperature limited heater approaches or exceeds the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor, reduction in the ferromagnetic properties of the ferromagnetic conductor allows electrical current to flow through a greater portion of the electrically conducting cross section of the temperature limited heater. Thus, the electrical resistance of the temperature limited heater is reduced and the temperature limited heater automatically provides reduced heat output at or near the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. In certain embodiments, a highly electrically conductive member is coupled to the ferromagnetic conductor and the electrical conductor to reduce the electrical resistance of the temperature

limited heater at or above the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. The highly electrically conductive member may be an inner conductor, a core, or another conductive member of copper, aluminum, nickel, or alloys thereof.

[0723] The ferromagnetic conductor that confines the majority of the flow of electrical current to the electrical conductor at temperatures below the Curie temperature and/or the phase transformation temperature range may have a relatively small cross section compared to the ferromagnetic conductor in temperature limited heaters that use the ferromagnetic conductor to provide the majority of resistive heat output up to or near the Curie temperature and/or the phase transformation temperature range. A temperature limited heater that uses the electrical conductor to provide a majority of the resistive heat output below the Curie temperature and/or the phase transformation temperature range has low magnetic inductance at temperatures below the Curie temperature and/or the phase transformation temperature range because less current is flowing through the ferromagnetic conductor as compared to the temperature limited heater where the majority of the resistive heat output below the Curie temperature and/or the phase transformation temperature range is provided by the ferromagnetic material. Magnetic field (H) at radius (r) of the ferromagnetic conductor is proportional to the current (I) flowing through the ferromagnetic conductor and the core divided by the radius, or:

[0724] (EQN. 6) $H \propto I/r$.

[0725] Since only a portion of the current flows through the ferromagnetic conductor for a temperature limited heater that uses the outer conductor to provide a majority of the resistive heat output below the Curie temperature and/or the phase transformation temperature range, the magnetic field of the temperature limited heater may be significantly smaller than the magnetic field of the temperature limited heater where the majority of the current flows through the ferromagnetic material. The relative magnetic permeability (μ) may be large for small magnetic fields.

[0726] The skin depth (δ) of the ferromagnetic conductor is inversely proportional to the square root of the relative magnetic permeability (μ):

[0727] (EQN. 7) $\delta \propto (1/\mu)^{1/2}$.

[0728] Increasing the relative magnetic permeability decreases the skin depth of the ferromagnetic conductor. However, because only a portion of the current flows through the ferromagnetic conductor for temperatures below the Curie temperature and/or the phase transformation temperature range, the radius (or thickness) of the ferromagnetic conductor may be decreased for ferromagnetic materials with large relative magnetic permeabilities to compensate for the decreased skin depth while still allowing the skin effect to limit the

penetration depth of the electrical current to the electrical conductor at temperatures below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. The radius (thickness) of the ferromagnetic conductor may be between 0.3 mm and 8 mm, between 0.3 mm and 2 mm, or between 2 mm and 4 mm depending on the relative magnetic permeability of the ferromagnetic conductor. Decreasing the thickness of the ferromagnetic conductor decreases costs of manufacturing the temperature limited heater, as the cost of ferromagnetic material tends to be a significant portion of the cost of the temperature limited heater. Increasing the relative magnetic permeability of the ferromagnetic conductor provides a higher turndown ratio and a sharper decrease in electrical resistance for the temperature limited heater at or near the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor.

[0729] Ferromagnetic materials (such as purified iron or iron-cobalt alloys) with high relative magnetic permeabilities (for example, at least 200, at least 1000, at least 1 × 104, or at least 1 × 105) and/or high Curie temperatures (for example, at least 600 °C, at least 700 °C, or at least 800 °C) tend to have less corrosion resistance and/or less mechanical strength at high temperatures. The electrical conductor may provide corrosion resistance and/or high mechanical strength at high temperatures for the temperature limited heater. Thus, the ferromagnetic conductor may be chosen primarily for its ferromagnetic properties.

[0730] Confining the majority of the flow of electrical current to the electrical conductor below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor reduces variations in the power factor. Because only a portion of the electrical current flows through the ferromagnetic conductor below the Curie temperature and/or the phase transformation temperature range, the non-linear ferromagnetic properties of the ferromagnetic conductor have little or no effect on the power factor of the temperature limited heater, except at or near the Curie temperature and/or the phase transformation temperature range. Even at or near the Curie temperature and/or the phase transformation temperature range, the effect on the power factor is reduced compared to temperature limited heaters in which the ferromagnetic conductor provides a majority of the resistive heat output below the Curie temperature and/or the phase transformation temperature range. Thus, there is less or no need for external compensation (for example, variable capacitors or waveform modification) to adjust for changes in the inductive load of the temperature limited heater to maintain a relatively high power factor.

[0731] In certain embodiments, the temperature limited heater, which confines the majority of the flow of electrical current to the electrical conductor below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor, maintains the power factor above 0.85, above 0.9, or above 0.95 during use of the heater. Any reduction in the power

factor occurs only in sections of the temperature limited heater at temperatures near the Curie temperature and/or the phase transformation temperature range. Most sections of the temperature limited heater are typically not at or near the Curie temperature and/or the phase transformation temperature range during use. These sections have a high power factor that approaches 1.0. The power factor for the entire temperature limited heater is maintained above 0.85, above 0.9, or above 0.95 during use of the heater even if some sections of the heater have power factors below 0.85.

[0732] Maintaining high power factors allows for less expensive power supplies and/or control devices such as solid state power supplies or SCRs (silicon controlled rectifiers). These devices may fail to operate properly if the power factor varies by too large an amount because of inductive loads. With the power factors maintained at high values; however, these devices may be used to provide power to the temperature limited heater. Solid state power supplies have the advantage of allowing fine tuning and controlled adjustment of the power supplied to the temperature limited heater.

[0733] In some embodiments, transformers are used to provide power to the temperature limited heater. Multiple voltage taps may be made into the transformer to provide power to the temperature limited heater. Multiple voltage taps allows the current supplied to switch back and forth between the multiple voltages. This maintains the current within a range bound by the multiple voltage taps.

[0734] The highly electrically conductive member, or inner conductor, increases the turndown ratio of the temperature limited heater. In certain embodiments, thickness of the highly electrically conductive member is increased to increase the turndown ratio of the temperature limited heater. In some embodiments, the thickness of the electrical conductor is reduced to increase the turndown ratio of the temperature limited heater. In certain embodiments, the turndown ratio of the temperature limited heater is between 1.1 and 10, between 2 and 8, or between 3 and 6 (for example, the turndown ratio is at least 1.1, at least 2, or at least 3).

[0735] FIG. 37 depicts an embodiment of a temperature limited heater in which the support member provides a majority of the heat output below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. Core 508 is an inner conductor of the temperature limited heater. In certain embodiments, core 508 is a highly electrically conductive material such as copper or aluminum. In some embodiments, core 508 is a copper alloy that provides mechanical strength and good electrically conductivity such as a dispersion strengthened copper. In one embodiment, core 508 is Glidcop® (SCM Metal Products, Inc., Research Triangle Park, North Carolina, U.S.A.). Ferromagnetic conductor 512 is a thin layer of ferromagnetic material between electrical conductor 538 and core 508. In certain

embodiments, electrical conductor 538 is also support member 514. In certain embodiments, ferromagnetic conductor 512 is iron or an iron alloy. In some embodiments, ferromagnetic conductor 512 includes ferromagnetic material with a high relative magnetic permeability. For example, ferromagnetic conductor 512 may be purified iron such as Armco ingot iron (AK Steel Ltd., United Kingdom). Iron with some impurities typically has a relative magnetic permeability on the order of 400. Purifying the iron by annealing the iron in hydrogen gas (H_2) at 1450 °C increases the relative magnetic permeability of the iron. Increasing the relative magnetic permeability of ferromagnetic conductor 512 allows the thickness of the ferromagnetic conductor to be reduced. For example, the thickness of unpurified iron may be approximately 4.5 mm while the thickness of the purified iron is approximately 0.76 mm.

[0736] In certain embodiments, electrical conductor 538 provides support for ferromagnetic conductor 512 and the temperature limited heater. Electrical conductor 538 may be made of a material that provides good mechanical strength at temperatures near or above the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 512. In certain embodiments, electrical conductor 538 is a corrosion resistant member. Electrical conductor 538 (support member 514) may provide support for ferromagnetic conductor 512 and corrosion resistance. Electrical conductor 538 is made from a material that provides desired electrically resistive heat output at temperatures up to and/or above the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 512.

[0737] In an embodiment, electrical conductor 538 is 347H stainless steel. In some embodiments, electrical conductor 538 is another electrically conductive, good mechanical strength, corrosion resistant material. For example, electrical conductor 538 may be 304H, 316H, 347HH, NF709, Incoloy® 800H alloy (Inco Alloys International, Huntington, West Virginia, U.S.A.), Haynes® HR120® alloy, or Inconel® 617 alloy.

[0738] In some embodiments, electrical conductor 538 (support member 514) includes different alloys in different portions of the temperature limited heater. For example, a lower portion of electrical conductor 538 (support member 514) is 347H stainless steel and an upper portion of the electrical conductor (support member) is NF709. In certain embodiments, different alloys are used in different portions of the electrical conductor (support member) to increase the mechanical strength of the electrical conductor (support member) while maintaining desired heating properties for the temperature limited heater.

[0739] In some embodiments, ferromagnetic conductor 512 includes different ferromagnetic conductors in different portions of the temperature limited heater. Different ferromagnetic conductors may be used in different portions of the temperature limited heater to vary the Curie temperature and/or the phase transformation temperature range and, thus, the maximum

operating temperature in the different portions. In some embodiments, the Curie temperature and/or the phase transformation temperature range in an upper portion of the temperature limited heater is lower than the Curie temperature and/or the phase transformation temperature range in a lower portion of the heater. The lower Curie temperature and/or the phase transformation temperature range in the upper portion increases the creep-rupture strength lifetime in the upper portion of the heater.

[0740] In the embodiment depicted in FIG. 37, ferromagnetic conductor 512, electrical conductor 538, and core 508 are dimensioned so that the skin depth of the ferromagnetic conductor limits the penetration depth of the majority of the flow of electrical current to the support member when the temperature is below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. Thus, electrical conductor 538 provides a majority of the electrically resistive heat output of the temperature limited heater at temperatures up to a temperature at or near the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 512. In certain embodiments, the temperature limited heater depicted in FIG. 37 is smaller (for example, an outside diameter of 3 cm, 2.9 cm, 2.5 cm, or less) than other temperature limited heaters that do not use electrical conductor 538 to provide the majority of electrically resistive heat output. The temperature limited heater depicted in FIG. 37 may be smaller because ferromagnetic conductor 512 is thin as compared to the size of the ferromagnetic conductor needed for a temperature limited heater in which the majority of the resistive heat output is provided by the ferromagnetic conductor.

[0741] In some embodiments, the support member and the corrosion resistant member are different members in the temperature limited heater. FIGS. 38 and 39 depict embodiments of temperature limited heaters in which the jacket provides a majority of the heat output below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. In these embodiments, electrical conductor 538 is jacket 506. Electrical conductor 538, ferromagnetic conductor 512, support member 514, and core 508 (in FIG. 38) or inner conductor 490 (in FIG. 39) are dimensioned so that the skin depth of the ferromagnetic conductor limits the penetration depth of the majority of the flow of electrical current to the thickness of the jacket. In certain embodiments, electrical conductor 538 is a material that is corrosion resistant and provides electrically resistive heat output below the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 512. For example, electrical conductor 538 is 825 stainless steel or 347H stainless steel. In some embodiments, electrical conductor 538 has a small thickness (for example, on the order of 0.5 mm).

[0742] In FIG. 38, core 508 is highly electrically conductive material such as copper or aluminum. Support member 514 is 347H stainless steel or another material with good

mechanical strength at or near the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 512.

[0743] In FIG. 39, support member 514 is the core of the temperature limited heater and is 347H stainless steel or another material with good mechanical strength at or near the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 512. Inner conductor 490 is highly electrically conductive material such as copper or aluminum.

[0744] In certain embodiments, the materials and design of the temperature limited heater are chosen to allow use of the heater at high temperatures (for example, above 850 °C). FIG. 40 depicts a high temperature embodiment of the temperature limited heater. The heater depicted in FIG. 40 operates as a conductor-in-conduit heater with the majority of heat being generated in conduit 518. The conductor-in-conduit heater may provide a higher heat output because the majority of heat is generated in conduit 518 rather than conductor 516. Having the heat generated in conduit 518 reduces heat losses associated with transferring heat between the conduit and conductor 516.

[0745] Core 508 and conductive layer 510 are copper. In some embodiments, core 508 and conductive layer 510 are nickel if the operating temperatures is to be near or above the melting point of copper. Support members 514 are electrically conductive materials with good mechanical strength at high temperatures. Materials for support members 514 that withstand at least a maximum temperature of about 870 °C may be, but are not limited to, MO-RE® alloys (Duraloy Technologies, Inc. (Scottdale, Pennsylvania, U.S.A.)), CF8C+ (Metaltek Intl. (Waukesha, Wisconsin, U.S.A.)), or Inconel® 617 alloy. Materials for support members 514 that withstand at least a maximum temperature of about 980 °C include, but are not limited to, Incoloy® Alloy MA 956. Support member 514 in conduit 518 provides mechanical support for the conduit. Support member 514 in conductor 516 provides mechanical support for core 508.

[0746] Electrical conductor 538 is a thin corrosion resistant material. In certain embodiments, electrical conductor 538 is 347H, 617, 625, or 800H stainless steel. Ferromagnetic conductor 512 is a high Curie temperature ferromagnetic material such as iron-cobalt alloy (for example, a 15% by weight cobalt, iron-cobalt alloy).

[0747] In certain embodiments, electrical conductor 538 provides the majority of heat output of the temperature limited heater at temperatures up to a temperature at or near the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 512. Conductive layer 510 increases the turndown ratio of the temperature limited heater.

[0748] For long vertical temperature limited heaters (for example, heaters at least 300 m, at least 500 m, or at least 1 km in length), the hanging stress becomes important in the selection of materials for the temperature limited heater. Without the proper selection of material, the support

member may not have sufficient mechanical strength (for example, creep-rupture strength) to support the weight of the temperature limited heater at the operating temperatures of the heater. FIG. 41 depicts hanging stress (ksi (kilopounds per square inch)) versus outside diameter (in.) for the temperature limited heater shown in FIG. 37 with 347H as the support member. The hanging stress was assessed with the support member outside a 0.5" copper core and a 0.75" outside diameter carbon steel ferromagnetic conductor. This assessment assumes the support member bears the entire load of the heater and that the heater length is 1000 ft. (about 305 m). As shown in FIG. 41, increasing the thickness of the support member decreases the hanging stress on the support member. Decreasing the hanging stress on the support member allows the temperature limited heater to operate at higher temperatures.

[0749] In certain embodiments, materials for the support member are varied to increase the maximum allowable hanging stress at operating temperatures of the temperature limited heater and, thus, increase the maximum operating temperature of the temperature limited heater. Altering the materials of the support member affects the heat output of the temperature limited heater below the Curie temperature and/or the phase transformation temperature range because changing the materials changes the resistance versus temperature profile of the support member. In certain embodiments, the support member is made of more than one material along the length of the heater so that the temperature limited heater maintains desired operating properties (for example, resistance versus temperature profile below the Curie temperature and/or the phase transformation temperature range) as much as possible while providing sufficient mechanical properties to support the heater.

[0750] FIG. 42 depicts hanging stress (ksi) versus temperature (°F) for several materials and varying outside diameters for the temperature limited heaters. Curve 540 is for 347H stainless steel. Curve 542 is for Incoloy® alloy 800H. Curve 544 is for Haynes® HR120® alloy. Curve 546 is for NF709. Each of the curves includes four points that represent various outside diameters of the support member. The point with the highest stress for each curve corresponds to outside diameter of 1.05". The point with the second highest stress for each curve corresponds to outside diameter of 1.15". The point with the second lowest stress for each curve corresponds to outside diameter of 1.25". The point with the lowest stress for each curve corresponds to outside diameter of 1.315". As shown in FIG. 42, increasing the strength and/or outside diameter of the material and the support member increases the maximum operating temperature of the temperature limited heater.

[0751] FIGS. 43, 44, 45, and 46 depict examples of embodiments for temperature limited heaters able to provide desired heat output and mechanical strength for operating temperatures up to about 770 °C for 30,000 hrs. creep-rupture lifetime. The depicted temperature limited heaters

have lengths of 1000 ft, copper cores of 0.5" diameter, and iron ferromagnetic conductors with outside diameters of 0.765". In FIG. 43, the support member in heater portion 548 is 347H stainless steel. The support member in heater portion 550 is Incoloy® alloy 800H. Portion 548 has a length of 750 ft. and portion 550 has a length of 250 ft. The outside diameter of the support member is 1.315". In FIG. 44, the support member in heater portion 548 is 347H stainless steel. The support member in heater portion 550 is Incoloy® alloy 800H. The support member in heater portion 552 is Haynes® HR120® alloy. Portion 548 has a length of 650 ft., portion 550 has a length of 300 ft., and portion 552 has a length of 50 ft. The outside diameter of the support member is 1.15". In FIG. 45, the support member in heater portion 548 is 347H stainless steel. The support member in heater portion 550 is Incoloy® alloy 800H. The support member in heater portion 552 is Haynes® HR120® alloy. Portion 548 has a length of 550 ft., portion 550 has a length of 250 ft., and portion 552 has a length of 200 ft. The outside diameter of the support member is 1.05".

[0752] In some embodiments, a transition section is used between sections of the heater. For example, if one or more portions of the heater have varying Curie temperatures and/or phase transformation temperature ranges, a transition section may be used between portions to provide strength that compensates for the differences in temperatures in the portions. FIG. 46 depicts another example of an embodiment of a temperature limited heater able to provide desired heat output and mechanical strength. The support member in heater portion 548 is 347H stainless steel. The support member in heater portion 550 is NF709. The support member in heater portion 552 is 347H. Portion 548 has a length of 550 ft. and a Curie temperature of 843 °C, portion 550 has a length of 250 ft. and a Curie temperature of 843 °C, and portion 552 has a length of 180 ft. and a Curie temperature of 770 °C. Transition section 554 has a length of 20 ft., a Curie temperature of 770 °C, and the support member is NF709.

[0753] The materials of the support member along the length of the temperature limited heater may be varied to achieve a variety of desired operating properties. The choice of the materials of the temperature limited heater is adjusted depending on a desired use of the temperature limited heater. TABLE 2 lists examples of materials that may be used for the support member. The table provides the hanging stresses (σ) of the support members and the maximum operating temperatures of the temperature limited heaters for several different outside diameters (OD) of the support member. The core diameter and the outside diameter of the iron ferromagnetic conductor in each case are 0.5" and 0.765", respectively.

TABLE 2

Material	OD = 1.05"	OD = 1.15"	OD = 1.25"	OD = 1.315"

	σ (ksi)	T (°F)	σ (ksi)	T (°F)	σ (ksi)	T (°F)	σ (ksi)	T (°F)
347H stainless steel	7.55	1310	6.33	1340	5.63	1360	5.31	1370
Incoloy® alloy 800H	7.55	1337	6.33	1378	5.63	1400	5.31	1420
Haynes® HR120® alloy	7.57	1450	6.36	1492	5.65	1520	5.34	1540
HA230	7.91	1475	6.69	1510	5.99	1530	5.67	1540
Haynes® alloy 556	7.65	1458	6.43	1492	5.72	1512	5.41	1520
NF709	7.57	1440	6.36	1480	5.65	1502	5.34	1512

[0754] In certain embodiments, one or more portions of the temperature limited heater have varying outside diameters and/or materials to provide desired properties for the heater. FIGS. 47 and 48 depict examples of embodiments for temperature limited heaters that vary the diameter and/or materials of the support member along the length of the heaters to provide desired operating properties and sufficient mechanical properties (for example, creep-rupture strength properties) for operating temperatures up to about 834 °C for 30,000 hrs., heater lengths of 850 ft, a copper core diameter of 0.5", and an iron-cobalt (6% by weight cobalt) ferromagnetic conductor outside diameter of 0.75". In FIG. 47, portion 548 is 347H stainless steel with a length of 300 ft and an outside diameter of 1.15". Portion 550 is NF709 with a length of 400 ft and an outside diameter of 1.15". Portion 552 is NF709 with a length of 150 ft and an outside diameter of 1.25". In FIG. 48, portion 548 is 347H stainless steel with a length of 300 ft and an outside diameter of 1.15". Portion 550 is 347H stainless steel with a length of 100 ft and an outside diameter of 1.20". Portion 552 is NF709 with a length of 350 ft and an outside diameter of 1.20". Portion 556 is NF709 with a length of 100 ft and an outside diameter of 1.25".

[0755] In certain embodiments, one or more portions of the temperature limited heater have varying dimensions and/or varying materials to provide different power outputs along the length of the heater. More or less power output may be provided by varying the selected temperature (for example, the Curie temperature and/or the phase transformation temperature range) of the temperature limited heater by using different ferromagnetic materials along its length and/or by varying the electrical resistance of the heater by using different dimensions in the heat generating member along the length of the heater. Different power outputs along the length of the temperature limited heater may be needed to compensate for different thermal properties in the formation adjacent to the heater. For example, an oil shale formation may have different water-

filled porosities, dawsonite compositions, and/or nahcolite compositions at different depths in the formation. Portions of the formation with higher water-filled porosities, higher dawsonite compositions, and/or higher nahcolite compositions may need more power input than portions with lower water-filled porosities, lower dawsonite compositions, and/or lower nahcolite compositions to achieve a similar heating rate. Power output may be varied along the length of the heater so that the portions of the formation with different properties (such as water-filled porosities, dawsonite compositions, and/or nahcolite compositions) are heated at approximately the same heating rate.

[0756] In certain embodiments, portions of the temperature limited heater have different selected self-limiting temperatures (for example, Curie temperatures and/or phase transformation temperature ranges), materials, and/or dimensions to compensate for varying thermal properties of the formation along the length of the heater. For example, Curie temperatures, phase transformation temperature ranges, support member materials, and/or dimensions of the portions of the heaters depicted in FIGS. 43-48 may be varied to provide varying power outputs and/or operating temperatures along the length of the heater.

[0757] As one example, in an embodiment of the temperature limited heater depicted in FIG. 43, portion 550 may be used to heat portions of the formation that, on average, have higher water-filled porosities, dawsonite compositions, and/or nahcolite compositions than portions of the formation heated by portion 548. Portion 550 may provide less power output than portion 548 to compensate for the differing thermal properties of the different portions of the formation so that the entire formation is heated at an approximately constant heating rate. Portion 550 may require less power output because, for example, portion 550 is used to heat portions of the formation with low water-filled porosities and/or little or no dawsonite. In one embodiment, portion 550 has a Curie temperature of 770 °C (pure iron) and portion 548 has a Curie temperature of 843 °C (iron with added cobalt). Such an embodiment may provide more power output from portion 548 so that the temperature lag between the two portions is reduced. Adjusting the Curie temperature of portions of the heater adjusts the selected temperature at which the heater self-limits. In some embodiments, the dimensions of portion 550 are adjusted to further reduce the temperature lag so that the formation is heated at an approximately constant heating rate throughout the formation. Dimensions of the heater may be adjusted to adjust the heating rate of one or more portions of the heater. For example, the thickness of an outer conductor in portion 550 may be increased relative to the ferromagnetic member and/or the core of the heater so that the portion has a higher electrical resistance and the portion provides a higher power output below the Curie temperature of the portion.

[0758] Reducing the temperature lag between different portions of the formation may reduce the overall time needed to bring the formation to a desired temperature. Reducing the time needed to bring the formation to the desired temperature reduces heating costs and produces desirable production fluids more quickly.

[0759] Temperature limited heaters with varying Curie temperatures and/or phase transformation temperature ranges may also have varying support member materials to provide mechanical strength for the heater (for example, to compensate for hanging stress of the heater and/or provide sufficient creep-rupture strength properties). For example, in the embodiment of the temperature limited heater depicted in FIG. 46, portions 548 and 550 have a Curie temperature of 843 °C. Portion 548 has a support member made of 347H stainless steel. Portion 550 has a support member made of NF709. Portion 552 has a Curie temperature of 770 °C and a support member made of 347H stainless steel. Transition section 554 has a Curie temperature of 770 °C and a support member made of NF709. Transition section 554 may be short in length compared to portions 548, 550, and 552. Transition section 554 may be placed between portions 550 and 552 to compensate for the temperature and material differences between the portions. For example, transition section 554 may be used to compensate for differences in creep properties between portions 550 and 552.

[0760] Such a substantially vertical temperature limited heater may have less expensive, lower strength materials in portion 552 because of the lower Curie temperature in this portion of the heater. For example, 347H stainless steel may be used for the support member because of the lower maximum operating temperature of portion 552 as compared to portion 550. Portion 550 may require more expensive, higher strength material because of the higher operating temperature of portion 550 due to the higher Curie temperature in this portion.

[0761] In some embodiments, a relatively thin conductive layer is used to provide the majority of the electrically resistive heat output of the temperature limited heater at temperatures up to a temperature at or near the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor. Such a temperature limited heater may be used as the heating member in an insulated conductor heater. The heating member of the insulated conductor heater may be located inside a sheath with an insulation layer between the sheath and the heating member.

[0762] FIGS. 49A and 49B depict cross-sectional representations of an embodiment of the insulated conductor heater with the temperature limited heater as the heating member. Insulated conductor 558 includes core 508, ferromagnetic conductor 512, inner conductor 490, electrical insulator 500, and jacket 506. Core 508 is a copper core. Ferromagnetic conductor 512 is, for example, iron or an iron alloy.

[0763] Inner conductor 490 is a relatively thin conductive layer of non-ferromagnetic material with a higher electrical conductivity than ferromagnetic conductor 512. In certain embodiments, inner conductor 490 is copper. Inner conductor 490 may be a copper alloy. Copper alloys typically have a flatter resistance versus temperature profile than pure copper. A flatter resistance versus temperature profile may provide less variation in the heat output as a function of temperature up to the Curie temperature and/or the phase transformation temperature range. In some embodiments, inner conductor 490 is copper with 6% by weight nickel (for example, CuNi6 or LOHM™). In some embodiments, inner conductor 490 is CuNi10Fe1Mn alloy. Below the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 512, the magnetic properties of the ferromagnetic conductor confine the majority of the flow of electrical current to inner conductor 490. Thus, inner conductor 490 provides the majority of the resistive heat output of insulated conductor 558 below the Curie temperature and/or the phase transformation temperature range.

[0764] In certain embodiments, inner conductor 490 is dimensioned, along with core 508 and ferromagnetic conductor 512, so that the inner conductor provides a desired amount of heat output and a desired turndown ratio. For example, inner conductor 490 may have a cross-sectional area that is around 2 or 3 times less than the cross-sectional area of core 508. Typically, inner conductor 490 has to have a relatively small cross-sectional area to provide a desired heat output if the inner conductor is copper or copper alloy. In an embodiment with copper inner conductor 490, core 508 has a diameter of 0.66 cm, ferromagnetic conductor 512 has an outside diameter of 0.91 cm, inner conductor 490 has an outside diameter of 1.03 cm, electrical insulator 500 has an outside diameter of 1.53 cm, and jacket 506 has an outside diameter of 1.79 cm. In an embodiment with a CuNi6 inner conductor 490, core 508 has a diameter of 0.66 cm, ferromagnetic conductor 512 has an outside diameter of 0.91 cm, inner conductor 490 has an outside diameter of 1.12 cm, electrical insulator 500 has an outside diameter of 1.63 cm, and jacket 506 has an outside diameter of 1.88 cm. Such insulated conductors are typically smaller and cheaper to manufacture than insulated conductors that do not use the thin inner conductor to provide the majority of heat output below the Curie temperature and/or the phase transformation temperature range.

[0765] Electrical insulator 500 may be magnesium oxide, aluminum oxide, silicon dioxide, beryllium oxide, boron nitride, silicon nitride, or combinations thereof. In certain embodiments, electrical insulator 500 is a compacted powder of magnesium oxide. In some embodiments, electrical insulator 500 includes beads of silicon nitride.

[0766] In certain embodiments, a small layer of material is placed between electrical insulator 500 and inner conductor 490 to inhibit copper from migrating into the electrical insulator at

higher temperatures. For example, the small layer of nickel (for example, about 0.5 mm of nickel) may be placed between electrical insulator 500 and inner conductor 490.

[0767] Jacket 506 is made of a corrosion resistant material such as, but not limited to, 347 stainless steel, 347H stainless steel, 446 stainless steel, or 825 stainless steel. In some embodiments, jacket 506 provides some mechanical strength for insulated conductor 558 at or above the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 512. In certain embodiments, jacket 506 is not used to conduct electrical current.

[0768] In certain embodiments of temperature limited heaters, three temperature limited heaters are coupled together in a three-phase wye configuration. Coupling three temperature limited heaters together in the three-phase wye configuration lowers the current in each of the individual temperature limited heaters because the current is split between the three individual heaters. Lowering the current in each individual temperature limited heater allows each heater to have a small diameter. The lower currents allow for higher relative magnetic permeabilities in each of the individual temperature limited heaters and, thus, higher turndown ratios. In addition, there may be no return current needed for each of the individual temperature limited heaters. Thus, the turndown ratio remains higher for each of the individual temperature limited heaters than if each temperature limited heater had its own return current path.

[0769] In the three-phase wye configuration, individual temperature limited heaters may be coupled together by shorting the sheaths, jackets, or canisters of each of the individual temperature limited heaters to the electrically conductive sections (the conductors providing heat) at their terminating ends (for example, the ends of the heaters at the bottom of a heater wellbore). In some embodiments, the sheaths, jackets, canisters, and/or electrically conductive sections are coupled to a support member that supports the temperature limited heaters in the wellbore.

[0770] FIG. 50A depicts an embodiment for installing and coupling heaters in a wellbore. The embodiment in FIG. 50A depicts insulated conductor heaters being installed into the wellbore. Other types of heaters, such as conductor-in-conduit heaters, may also be installed in the wellbore using the embodiment depicted. Also, in FIG. 50A, two insulated conductors 558 are shown while a third insulated conductor is not seen from the view depicted. Typically, three insulated conductors 558 would be coupled to support member 560, as shown in FIG. 50B. In an embodiment, support member 560 is a thick walled 347H pipe. In some embodiments, thermocouples or other temperature sensors are placed inside support member 560. The three insulated conductors may be coupled in a three-phase wye configuration.

[0771] In FIG. 50A, insulated conductors 558 are coiled on coiled tubing rigs 562. As insulated conductors 558 are uncoiled from rigs 562, the insulated conductors are coupled to support member 560. In certain embodiments, insulated conductors 558 are simultaneously uncoiled

and/or simultaneously coupled to support member 560. Insulated conductors 558 may be coupled to support member 560 using metal (for example, 304 stainless steel or Inconel® alloys) straps 564. In some embodiments, insulated conductors 558 are coupled to support member 560 using other types of fasteners such as buckles, wire holders, or snaps. Support member 560 along with insulated conductors 558 are installed into opening 522. In some embodiments, insulated conductors 558 are coupled together without the use of a support member. For example, one or more straps 564 may be used to couple insulated conductors 558 together.

[0772] Insulated conductors 558 may be electrically coupled to each other at a lower end of the insulated conductors. In a three-phase wye configuration, insulated conductors 558 operate without a current return path. In certain embodiments, insulated conductors 558 are electrically coupled to each other in contactor section 566. In section 566, sheaths, jackets, canisters, and/or electrically conductive sections are electrically coupled to each other and/or to support member 560 so that insulated conductors 558 are electrically coupled in the section.

[0773] In certain embodiments, the sheaths of insulated conductors 558 are shorted to the conductors of the insulated conductors. FIG. 50C depicts an embodiment of insulated conductor 558 with the sheath shorted to the conductors. Sheath 506 is electrically coupled to core 508, ferromagnetic conductor 512, and inner conductor 490 using termination 568. Termination 568 may be a metal strip or a metal plate at the lower end of insulated conductor 558. For example, termination 568 may be a copper plate coupled to sheath 506, core 508, ferromagnetic conductor 512, and inner conductor 490 so that they are shorted together. In some embodiments, termination 568 is welded or brazed to sheath 506, core 508, ferromagnetic conductor 512, and inner conductor 490.

[0774] The sheaths of individual insulated conductors 558 may be shorted together to electrically couple the conductors of the insulated conductors, depicted in FIGS. 50A and 50B. In some embodiments, the sheaths may be shorted together because the sheaths are in physical contact with each other. For example, the sheaths may in physical contact if the sheaths are strapped together by straps 564. In some embodiments, the lower ends of the sheaths are physically coupled (for example, welded) at the surface of opening 522 before insulated conductors 558 are installed into the opening.

[0775] In certain embodiments, coupling multiple heaters (for example, insulated conductor, or mineral insulated conductor, heaters) to a single power source, such as a transformer, is advantageous. Coupling multiple heaters to a single transformer may result in using fewer transformers to power heaters used for a treatment area as compared to using individual transformers for each heater. Using fewer transformers reduces surface congestion and allows easier access to the heaters and surface components. Using fewer transformers reduces capital

costs associated with providing power to the treatment area. In some embodiments, at least 4, at least 5, at least 10, at least 25 heaters, at least 35 heaters, or at least 45 heaters are powered by a single transformer. Additionally, powering multiple heaters (in different heater wells) from the single transformer may reduce overburden losses because of reduced voltage and/or phase differences between each of the heater wells powered by the single transformer. Powering multiple heaters from the single transformer may inhibit current imbalances between the heaters because the heaters are coupled to the single transformer.

[0776] In order to provide power to multiple heaters using the single transformer, the transformer may have to provide power at higher voltages to carry the current to each of the heaters effectively. In certain embodiments, the heaters are floating (ungrounded) heaters in the formation. Floating the heaters allows the heaters to operate at higher voltages. In some embodiments, the transformer provides power output of at least about 3 kV, at least about 4 kV, at least about 5 kV, or at least about 6 kV.

[0777] FIG. 51 depicts a top view representation of heater 716 with three insulated conductors 558 in conduit 536. Heater 716 includes three insulated conductors 558 in conduit 536. Heater 716 may be located in a heater well in the subsurface formation. Conduit 536 may be a sheath, jacket, or other enclosure around insulated conductors 558. Each insulated conductor 558 includes core 508, electrical insulator 500, and jacket 506. Insulated conductors 558 may be mineral insulated conductors with core 508 being a copper alloy (for example, a copper-nickel alloy such as Alloy 180), electrical insulator 500 being magnesium oxide, and jacket 506 being Incoloy® 825, copper, or stainless steel (for example 347H stainless steel). In some embodiments, jacket 506 includes non-work hardenable metals so that the jacket is annealable.

[0778] In some embodiments, core 508 and/or jacket 506 include ferromagnetic materials. In some embodiments, one or more insulated conductors 558 are temperature limited heaters. In certain embodiments, the overburden portion of insulated conductors 558 include high electrical conductivity materials in core 508 (for example, pure copper or copper alloys such as copper with 3% silicon at a weld joint) so that the overburden portions of the insulated conductors provide little or no heat output. In certain embodiments, conduit 536 includes non-corrosive materials and/or high strength materials such as stainless steel. In one embodiment, conduit 536 is 347H stainless steel.

[0779] Insulated conductors 558 may be coupled to the single transformer in a three-phase configuration (for example, a three-phase wye configuration). Each insulated conductor 558 may be coupled to one phase of the single transformer. In certain embodiments, the single transformer is also coupled to a plurality of identical heaters 716 in other heater wells in the formation (for example, the single transformer may couple to 40 heaters or more 716 in the

formation). In some embodiments, the single transformer couples to at least 4, at least 5, at least 10, at least 15, or at least 25 additional heaters in the formation.

[0780] FIG. 52 depicts an embodiment of three-phase wye transformer 728 coupled to a plurality of heaters 716. For simplicity in the drawing, only four heaters 716 are shown in FIG. 52. It is to be understood that several more heaters may be coupled to the transformer 728. As shown in FIG. 52, each leg (each insulated conductor) of each heater is coupled to one phase of transformer 728 and current returned to the neutral or ground of the transformer (for example, returned through conductor 2024 depicted in FIGS. 51 and 53).

[0781] Electrical insulator 500' may be located inside conduit 536 to electrically insulate insulated conductors 558 from the conduit. In certain embodiments, electrical insulator 500' is magnesium oxide (for example, compacted magnesium oxide). In some embodiments, electrical insulator 500' is silicon nitride (for example, silicon nitride blocks). Electrical insulator 500' electrically insulates insulated conductors 558 from conduit 536 so that at high operating voltages (for example, 3 kV or higher), there is no arcing between the conductors and the conduit. In some embodiments, electrical insulator 500' inside conduit 536 has at least the thickness of electrical insulators 500 in insulated conductors 558. The increased thickness of insulation in heater 716 (from electrical insulators 500 and/or electrical insulator 500') inhibits and may prevent current leakage into the formation from the heater. In some embodiments, electrical insulator 500' spatially locates insulated conductors 558 inside conduit 536.

[0782] Return conductor 2024 may be electrically coupled to the ends of insulated conductors 558 (as shown in FIG. 53) and return current from the ends of the insulated conductors to the transformer on the surface of the formation. Return conductor 2024 may include high electrical conductivity materials such as pure copper, nickel, copper alloys, or combinations thereof so that the return conductor provides little or no heat output. In some embodiments, return conductor 2024 is a tubular (for example, a stainless steel tubular) that allows an optical fiber to be placed inside the tubular and used for temperature measurement. In some embodiments, return conductor 2024 is a small insulated conductor (for example, small mineral insulated conductor). Return conductor 2024 may be coupled to the neutral or ground leg of the transformer in a three-phase wye configuration. Thus, insulated conductors 558 are electrically isolated from conduit 536 and the formation. Using return conductor 2024 to return current to the surface may make coupling the heater to a wellhead easier. In some embodiments, current is returned using one or more of jackets 506, depicted in FIG. 51. One or more jackets 506 may be coupled to cores 508 at the end of the heaters and return current to the neutral of the three-phase wye transformer.

[0783] FIG. 53 depicts a side view representation of the end section of three insulated conductors 558 in conduit 536. The end section is the section of the heaters the furthest away from (distal

from) the surface of the formation. The end section includes contactor section 566 coupled to conduit 536. In some embodiments, contactor section 566 is welded or brazed to conduit 536. Termination 568 is located in contactor section 566. Termination 568 is electrically coupled to insulated conductors 558 and return conductor 2024. Termination 568 electrically couples the cores of insulated conductors 558 to the return conductor 2024 at the ends of the heaters.

[0784] In certain embodiments, heater 716, depicted in FIGS. 51 and 53, includes an overburden section using copper as the core of the insulated conductors. The copper in the overburden section may be the same diameter as the cores used in the heating section of the heater. The copper in the overburden section may also have a larger diameter than the cores in the heating section of the heater. Increasing the size of the copper in the overburden section may decrease losses in the overburden section of the heater.

[0785] Heaters that include three insulated conductors 558 in conduit 536, as depicted in FIGS. 51 and 53, may be made in a multiple step process. In some embodiments, the multiple step process is performed at the site of the formation or treatment area. In some embodiments, the multiple step process is performed at a remote manufacturing site away from the formation. The finished heater is then transported to the treatment area.

[0786] Insulated conductors 558 may be pre-assembled prior to the bundling either on site or at a remote location. Insulated conductors 558 and return conductor 2024 may be positioned on spools. A machine may draw insulated conductors 558 and return conductor 2024 from the spools at a selected rate. Preformed blocks of insulation material may be positioned around return conductor 2024 and insulated conductors 558. In an embodiment, two blocks are positioned around return conductor 2024 and three blocks are positioned around insulated conductors 558 to form electrical insulator 500'. The insulated conductors and return conductor may be drawn or pushed into a plate of conduit material that has been rolled into a tubular shape. The edges of the plate may be pressed together and welded (for example, by laser welding). After forming conduit 536 around electrical insulator 500', the bundle of insulated conductors 558, and return conductor 2024, the conduit may be compacted against the electrical insulator 2024 so that all of the components of the heater are pressed together into a compact and tightly fitting form. During the compaction, the electrical insulator may flow and fill any gaps inside the heater.

[0787] In some embodiments, heater 716 (which includes conduit 536 around electrical insulator 500' and the bundle of insulated conductors 558 and return conductor 2024) is inserted into a coiled tubing tubular that is placed in a wellbore in the formation. The coiled tubing tubular may be left in place in the formation (left in during heating of the formation) or removed from the

formation after installation of the heater. The coiled tubing tubular may allow for easier installation of heater 716 into the wellbore.

[0788] In some embodiments, one or more components of heater 716 are varied (for example, removed, moved, or replaced) while the operation of the heater remains substantially identical. FIG. 54 depicts one alternative embodiment of heater 716 with three insulated cores 508 in conduit 536. In this embodiment, electrical insulator 500' surrounds cores 508 and return conductor 2024 in conduit 536. Cores 508 are located in conduit 536 without electrical insulator 500 and jacket 506 surrounding the cores. Cores 508 are coupled to the single transformer in a three-phase wye configuration with each core 508 coupled to one phase of the transformer. Return conductor 2024 is electrically coupled to the ends of cores 508 and returns current from the ends of the cores to the transformer on the surface of the formation.

[0789] FIG. 55 depicts another alternative embodiment of heater 716 with three insulated conductors 558 and insulated return conductor in conduit 536. In this embodiment, return conductor 2024 is an insulated conductor with core 508, electrical insulator 500, and jacket 506. Return conductor 2024 and insulated conductors 558 are located in conduit 536 are surrounded by electrical insulator 500 and conduit 536. Return conductor 2024 and insulated conductors 558 may be the same size or different sizes. Return conductor 2024 and insulated conductors 558 operate substantially the same as in the embodiment depicted in FIGS. 51 and 53.

[0790] FIG. 56 depicts an embodiment of insulated conductor 558 in conduit 518 with molten metal. Insulated conductor 558 and conduit 518 may be placed in an opening in a subsurface formation. Insulated conductor 558 and conduit 518 may have any orientation in a subsurface formation (for example, the insulated conductor and conduit may be substantially vertical or substantially horizontally oriented in the formation). Insulated conductor 558 includes core 508, electrical insulator 500, and jacket 506. In some embodiments, core 508 is a copper core. In some embodiments, core 508 includes other electrical conductors or alloys (for example, copper alloys). In some embodiments, core 508 includes a ferromagnetic conductor so that insulated conductor 558 operates as a temperature limited heater.

[0791] Electrical insulator 500 may be magnesium oxide, aluminum oxide, silicon dioxide, beryllium oxide, boron nitride, silicon nitride, or combinations thereof. In certain embodiments, electrical insulator 500 is a compacted powder of magnesium oxide. In some embodiments, electrical insulator 500 includes beads of silicon nitride. In certain embodiments, a small layer of material is placed between electrical insulator 500 and core 508 to inhibit copper from migrating into the electrical insulator at higher temperatures. For example, the small layer of nickel (for example, about 0.5 mm of nickel) may be placed between electrical insulator 500 and core 508.

[0792] Jacket 506 is made of a corrosion resistant material such as, but not limited to, 347 stainless steel, 347H stainless steel, 446 stainless steel, or 825 stainless steel. In some embodiments, jacket 506 is not used to conduct electrical current.

[0793] In an embodiment, core 508 has a diameter of about 1 cm, electrical insulator 500 has an outside diameter of about 1.6 cm, and jacket 506 has an outside diameter of about 1.8 cm.

[0794] In certain embodiments, molten metal 2026 is placed inside conduit 518 in the space outside of insulated conductor 558. In certain embodiments, molten metal 2026 is placed in as balls or pellets of metal. The metal balls or pellets may be made of metal that melts below operating temperatures of insulated conductor 558 but above ambient subsurface formation temperatures. The metal balls or pellets may be placed in conduit 518 after insulated conductor 558 is placed in the conduit. In certain embodiments, molten metal 2026 is placed in as a molten liquid. The molten liquid may be placed in conduit 518 before or after insulated conductor 558 is placed in the conduit (for example, the molten liquid may be poured into the conduit before or after the insulated conductor is placed in the conduit). Additionally, the molten liquid, or the metal balls or pellets, may be placed in conduit 518 before or after insulated conductor 558 is energized (turned on).

[0795] Molten metal 2026 may remain a molten liquid at operating temperatures of insulated conductor 558. In some embodiments, molten metal 2026 melts at temperatures above about 100 °C, above about 200 °C, or above about 300 °C. Molten metal 2026 may remain a molten liquid at temperatures up to about 1400 °C, about 1500 °C, or about 1600 °C. In certain embodiments, molten metal 2026 is a good thermal conductor at or near the operating temperatures of insulated conductor 558. Molten metal 2026 may include metals such as tin, zinc, an alloy such as a 60% by weight tin, 40% by weight zinc alloy; bismuth; cadmium, aluminum; lead; arsenic; and/or combinations thereof. In one embodiment, molten metal 2026 is tin. Molten metal 2026 may have a high Grashof number. Molten metals with high Grashof numbers will provide good convection currents in conduit 518.

[0796] Molten metal 2026 fills the space between conduit 518 and insulated conductor 558. Molten metal 2026 may increase heat transfer between conduit 518 and insulated conductor 558 by heat conduction through the molten metal and/or heat convection from movement of the molten metal in the conduit. The temperature differential between conduit 518 and insulated conductor 558 may create convection currents (heat generated movement) in the conduit. Convection of molten metal 2026 may inhibit hot spots along conduit 518 and insulated conductor 558. Using molten metal 2026 allows insulated conductor 558 to be a smaller diameter insulated conductor, which may be easier and/or cheaper to manufacture.

[0797] In some embodiments, molten metal 2026 returns electrical current to the surface from insulated conductor 558 (the molten metal acts as the return or ground conductor for the insulated conductor). Molten metal 2026 may provide a large current path with low resistance so that a long heater (long insulated conductor 558) is useable in conduit 518. Molten metal 2026 may also inhibit ferromagnetic effects in conduit 518, which allows longer heaters with lower voltages. The long heater may operate at low voltages for the length of the heater due to the presence of molten metal 2026.

[0798] In certain embodiments, insulated conductor 558 is buoyant in the molten metal. The buoyancy of insulated conductor 558 reduces creep associated problems in long, substantially vertical heaters. A bottom weight or tie down may be coupled to the bottom of insulated conductor 558 to inhibit the insulated conductor from floating in the molten metal.

[0799] Conduit 518 may be a carbon steel or stainless steel canister. In an embodiment, conduit 518 is a canister of 410 stainless steel with an outside diameter of about 6 cm. Conduit 518 may have thin walls as molten metal 2026 may provide internal pressure that inhibits deformation or crushing of the conduit due to external stresses.

[0800] FIG. 57 depicts an embodiment of substantially horizontal insulated conductor 558 in conduit 518 with molten metal 2026. Molten metal 2026 may provide a head in conduit 518 due to the pressure of the molten metal. This pressure head may keep molten metal 2026 in conduit 518. The pressure head may also provide internal pressure that inhibits deformation or collapse of the conduit due to external stresses.

[0801] In some embodiments, a long temperature limited heater (for example, a temperature limited heater in which the support member provides a majority of the heat output below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic conductor) is formed from several sections of heater. The sections of heater may be coupled using a welding process. FIG. 58 depicts an embodiment for coupling together sections of a long temperature limited heater. Ends of ferromagnetic conductors 512 and ends of electrical conductors 538 (support members 514) are beveled to facilitate coupling the sections of the heater. Core 508 has recesses to allow core coupling material 570 to be placed inside the abutted ends of the heater. Core coupling material 570 may be a pin or dowel that fits tightly in the recesses of cores 508. Core coupling material 570 may be made out of the same material as cores 508 or a material suitable for coupling the cores together. Core coupling material 570 allows the heaters to be coupled together without welding cores 508 together. Cores 508 are coupled together as a "pin" or "box" joint.

[0802] Beveled ends of ferromagnetic conductors 512 and electrical conductors 538 may be coupled together with coupling material 572. In certain embodiments, ends of ferromagnetic

conductors 512 and electrical conductors 538 are welded (for example, orbital welded) together. Coupling material 572 may be 625 stainless steel or any other suitable non-ferromagnetic material for welding together ferromagnetic conductors 512 and/or electrical conductors 538. Using beveled ends when coupling together sections of the heater may produce a reliable and durable coupling between the sections of the heater.

[0803] During heating with the temperature limited heater, core coupling material 570 may expand more radially than ferromagnetic conductors 512, electrical conductors 538, and/or coupling material 572. The greater expansion of core coupling material 570 maintains good electrical contact with the core coupling material. At the coupling junction of the heater, electricity flows through core coupling material 570 rather than coupling material 572. This flow of electricity inhibits heat generation at the coupling junction so that the junction remains at lower temperatures than other portions of the heater during application of electrical current to the heater. The corrosion resistance and strength of the coupling junction is increased by maintaining the junction at lower temperatures.

[0804] In certain embodiments, the junction may be enclosed in a shield during orbital welding to enhance and/or ensure reliability of the weld. If the junction is not enclosed, disturbance of the inert gas caused by wind, humidity or other conditions may cause oxidation and/or porosity of the weld. Without a shield, a first portion of the weld was formed and allowed to cool. A grinder would be used to remove the oxide layer. The process would be repeated until the weld was complete. Enclosing the junction in the shield with an inert gas allows the weld to be formed with no oxidation, thus allowing the weld to be formed in one pass with no need for grinding. Enclosing the junction increases the safety of forming the weld because the arc of the orbital welder is enclosed in the shield during welding. Enclosing the junction in the shield may reduce the time needed to form the weld. Without a shield, producing each weld may take 30 minutes or more. With the shield, each weld may take 10 minutes or less.

[0805] FIG. 59 depicts an embodiment of a shield for orbital welding sections of a long temperature limited heater. Orbital welding may also be used to form canisters for freeze wells from sections of pipe. Shield 574 may include upper plate 576, lower plate 578, inserts 580, wall 582, hinged door 584, first clamp member 586, and second clamp member 588. Wall 582 may include one or more inert gas inlets. Wall 582, upper plate 576, and/or lower plate 578 may include one or more openings for monitoring equipment or gas purging. Shield 574 is configured to work with an orbital welder, such as AMI Power Supply (Model 227) and AMI Orbital Weld Head (Model 97-2375) available from Arc Machines, Inc. (Pacoima, California, U.S.A.). Inserts 580 may be withdrawn from upper plate 576 and lower plate 578. The orbital weld head may be positioned in shield 574. Shield 574 may be placed around a lower conductor of the conductors

that are to be welded together. When shield is positioned so that the end of the lower conductor is at a desired position in the middle of the shield, first clamp member may be fastened to second clamp member to secure shield 574 to the lower conductor. The upper conductor may be positioned in shield 574. Inserts 580 may be placed in upper plate 576 and lower plate 578.

[0806] Hinged door 584 may be closed. When hinged door 584 is closed, shield 574 forms a substantially airtight seal around the portions to be welded together. The orbital welder may be located inside the shield. The orbital welder may weld the lower conductor to the upper conductor. In certain embodiments, an inert gas (such as argon or krypton) is provided through openings (for example, gas feedthroughs) in wall 582. The inert gas may be provided so that the interior of shield 574 is substantially or completely flushed with the inert gas and any oxidizing fluid (for example, oxygen) is removed from inside the shield. A gas exit (for example, a gas outlet or gas exit feedthrough) may allow gas to be flushed through shield 574. Having the inert gas inside shield 574 during the welding process and removing oxidizing fluids (such as oxygen) from inside the shield, inhibits oxidization from occurring during the welding process. Inhibiting oxidation during the welding process inhibits the formation of oxide layers on the metals being welded and provides a more reliable welding process, a faster welding process, and a more reliable weld junction.

[0807] In certain embodiments, a positive pressure of inert gas is maintained inside shield 574 during the welding process. The positive pressure of inert gas inhibits outside gases (for example, oxygen or other oxidizing gases) from entering the shield, even if the shield has one or more leaks. In some embodiments, a vacuum may be pulled on shield 574 before providing the inert gas into the shield and/or before welding the portions together. Pulling a vacuum on the shield may remove contaminants such as particulates from inside the shield.

[0808] Progress of the welding operation may be monitored through viewing windows 590. When the weld is complete, shield 574 may be supported and first clamp member 586 may be unfastened from second clamp member 588. One or both inserts 580 may be removed or partially removed from lower plate 578 and upper plate 576 to facilitate lowering of the conductor. The conductor may be lowered in the wellbore until the end of the conductor is located at a desired position in shield 574. Shield 574 may be secured to the conductor with first clamp member 586 and second clamp member 588. Another conductor may be positioned in the shield. Inserts 580 may be positioned in upper and lower plates 576, 578; hinged door is closed 584; and the orbital welder is used to weld the conductors together. The process may be repeated until a desired length of conductor is formed.

[0809] The shield may be used to weld joints of pipe over an opening in the hydrocarbon containing formation. Hydrocarbon vapors from the formation may create an explosive

atmosphere in the shield even though the inert gas supplied to the shield inhibits the formation of dangerous concentrations of hydrocarbons in the shield. A control circuit may be coupled to a power supply for the orbital welder to stop power to the orbital welder to shut off the arc forming the weld if the hydrocarbon level in the shield rises above a selected concentration. FIG. 60 depicts a schematic representation of an embodiment of a shut off circuit for orbital welding machine 600. An inert gas, such as argon, may enter shield 574 through inlet 602. Gas may exit shield 574 through purge 604. Power supply 606 supplies electricity to orbital welding machine 600 through lines 608, 610. Switch 612 may be located in line 608 to orbital welding machine 600. Switch 612 may be electrically coupled to hydrocarbon monitor 614. Hydrocarbon monitor 614 may detect the hydrocarbon concentration in shield 574. If the hydrocarbon concentration in shield becomes too high, for example, over 25% of a lower explosion limit concentration, hydrocarbon monitor 614 may open switch 612. When switch 612 is open, power to orbital welder 600 is interrupted and the arc formed by the orbital welder ends.

[0810] In some embodiments, the temperature limited heater is used to achieve lower temperature heating (for example, for heating fluids in a production well, heating a surface pipeline, or reducing the viscosity of fluids in a wellbore or near wellbore region). Varying the ferromagnetic materials of the temperature limited heater allows for lower temperature heating. In some embodiments, the ferromagnetic conductor is made of material with a lower Curie temperature than that of 446 stainless steel. For example, the ferromagnetic conductor may be an alloy of iron and nickel. The alloy may have between 30% by weight and 42% by weight nickel with the rest being iron. In one embodiment, the alloy is Invar 36. Invar 36 is 36% by weight nickel in iron and has a Curie temperature of 277 °C. In some embodiments, an alloy is a three component alloy with, for example, chromium, nickel, and iron. For example, an alloy may have 6% by weight chromium, 42% by weight nickel, and 52% by weight iron. A 2.5 cm diameter rod of Invar 36 has a turndown ratio of approximately 2 to 1 at the Curie temperature. Placing the Invar 36 alloy over a copper core may allow for a smaller rod diameter. A copper core may result in a high turndown ratio. The insulator in lower temperature heater embodiments may be made of a high performance polymer insulator (such as PFA or PEEKTM) when used with alloys with a Curie temperature that is below the melting point or softening point of the polymer insulator.

[0811] In certain embodiments, a conductor-in-conduit temperature limited heater is used in lower temperature applications by using lower Curie temperature and/or the phase transformation temperature range ferromagnetic materials. For example, a lower Curie temperature and/or the phase transformation temperature range ferromagnetic material may be used for heating inside sucker pump rods. Heating sucker pump rods may be useful to lower the viscosity of fluids in

the sucker pump or rod and/or to maintain a lower viscosity of fluids in the sucker pump rod. Lowering the viscosity of the oil may inhibit sticking of a pump used to pump the fluids. Fluids in the sucker pump rod may be heated up to temperatures less than about 250 °C or less than about 300 °C. Temperatures need to be maintained below these values to inhibit coking of hydrocarbon fluids in the sucker pump system.

[0812] FIG. 61 depicts an embodiment of a temperature limited heater with a low temperature ferromagnetic outer conductor. Outer conductor 502 is glass sealing Alloy 42-6. Alloy 42-6 may be obtained from Carpenter Metals (Reading, Pennsylvania, U.S.A.) or Anomet Products, Inc. In some embodiments, outer conductor 502 includes other compositions and/or materials to get various Curie temperatures (for example, Carpenter Temperature Compensator "32" (Curie temperature of 199 °C; available from Carpenter Metals) or Invar 36). In an embodiment, conductive layer 510 is coupled (for example, clad, welded, or brazed) to outer conductor 502. Conductive layer 510 is a copper layer. Conductive layer 510 improves a turndown ratio of outer conductor 502. Jacket 506 is a ferromagnetic metal such as carbon steel. Jacket 506 protects outer conductor 502 from a corrosive environment. Inner conductor 490 may have electrical insulator 500. Electrical insulator 500 may be a mica tape winding with overlaid fiberglass braid. In an embodiment, inner conductor 490 and electrical insulator 500 are a 4/0 MGT-1000 furnace cable or 3/0 MGT-1000 furnace cable. 4/0 MGT-1000 furnace cable or 3/0 MGT-1000 furnace cable is available from Allied Wire and Cable (Phoenixville, Pennsylvania, U.S.A.). In some embodiments, a protective braid such as a stainless steel braid may be placed over electrical insulator 500.

[0813] Conductive section 504 electrically couples inner conductor 490 to outer conductor 502 and/or jacket 506. In some embodiments, jacket 506 touches or electrically contacts conductive layer 510 (for example, if the heater is placed in a horizontal configuration). If jacket 506 is a ferromagnetic metal such as carbon steel (with a Curie temperature above the Curie temperature of outer conductor 502), current will propagate only on the inside of the jacket. Thus, the outside of the jacket remains electrically uncharged during operation. In some embodiments, jacket 506 is drawn down (for example, swaged down in a die) onto conductive layer 510 so that a tight fit is made between the jacket and the conductive layer. The heater may be spooled as coiled tubing for insertion into a wellbore. In other embodiments, an annular space is present between conductive layer 510 and jacket 506, as depicted in FIG. 61.

[0814] FIG. 62 depicts an embodiment of a temperature limited conductor-in-conduit heater. Conduit 518 is a hollow sucker rod made of a ferromagnetic metal such as Alloy 42-6, Alloy 32, Alloy 52, Invar 36, iron-nickel-chromium alloys, iron-nickel alloys, nickel alloys, or nickel-chromium alloys. Inner conductor 490 has electrical insulator 500. Electrical insulator 500 is a

mica tape winding with overlaid fiberglass braid. In an embodiment, inner conductor 490 and electrical insulator 500 are a 4/0 MGT-1000 furnace cable or 3/0 MGT-1000 furnace cable. In some embodiments, polymer insulations are used for lower temperature, temperature limited heaters. In certain embodiments, a protective braid is placed over electrical insulator 500. Conduit 518 has a wall thickness that is greater than the skin depth at the Curie temperature (for example, 2 to 3 times the skin depth at the Curie temperature). In some embodiments, a more conductive conductor is coupled to conduit 518 to increase the turndown ratio of the heater.

[0815] FIG. 63 depicts a cross-sectional representation of an embodiment of a conductor-in-conduit temperature limited heater. Conductor 516 is coupled (for example, clad, coextruded, press fit, drawn inside) to ferromagnetic conductor 512. A metallurgical bond between conductor 516 and ferromagnetic conductor 512 is favorable. Ferromagnetic conductor 512 is coupled to the outside of conductor 516 so that current propagates through the skin depth of the ferromagnetic conductor at room temperature. Conductor 516 provides mechanical support for ferromagnetic conductor 512 at elevated temperatures. Ferromagnetic conductor 512 is iron, an iron alloy (for example, iron with 10% to 27% by weight chromium for corrosion resistance), or any other ferromagnetic material. In one embodiment, conductor 516 is 304 stainless steel and ferromagnetic conductor 512 is 446 stainless steel. Conductor 516 and ferromagnetic conductor 512 are electrically coupled to conduit 518 with sliding connector 528. Conduit 518 may be a non-ferromagnetic material such as austenitic stainless steel.

[0816] FIG. 64 depicts a cross-sectional representation of an embodiment of a conductor-in-conduit temperature limited heater. Conduit 518 is coupled to ferromagnetic conductor 512 (for example, clad, press fit, or drawn inside of the ferromagnetic conductor). Ferromagnetic conductor 512 is coupled to the inside of conduit 518 to allow current to propagate through the skin depth of the ferromagnetic conductor at room temperature. Conduit 518 provides mechanical support for ferromagnetic conductor 512 at elevated temperatures. Conduit 518 and ferromagnetic conductor 512 are electrically coupled to conductor 516 with sliding connector 528.

[0817] FIG. 65 depicts a cross-sectional view of an embodiment of a conductor-in-conduit temperature limited heater. Conductor 516 may surround core 508. In an embodiment, conductor 516 is 347H stainless steel and core 508 is copper. Conductor 516 and core 508 may be formed together as a composite conductor. Conduit 518 may include ferromagnetic conductor 512. In an embodiment, ferromagnetic conductor 512 is Sumitomo HCM12A or 446 stainless steel. Ferromagnetic conductor 512 may have a Schedule XXH thickness so that the conductor is inhibited from deforming. In certain embodiments, conduit 518 also includes jacket 506. Jacket 506 may include corrosion resistant material that inhibits electrons from flowing away from the

heater and into a subsurface formation at higher temperatures (for example, temperatures near the Curie temperature and/or the phase transformation temperature range of ferromagnetic conductor 512). For example, jacket 506 may be about a 0.4 cm thick sheath of 410 stainless steel. Inhibiting electrons from flowing to the formation may increase the safety of using the heater in the subsurface formation.

[0818] FIG. 66 depicts a cross-sectional representation of an embodiment of a conductor-in-conduit temperature limited heater with an insulated conductor. Insulated conductor 558 may include core 508, electrical insulator 500, and jacket 506. Jacket 506 may be made of a corrosion resistant material (for example, stainless steel). Endcap 616 may be placed at an end of insulated conductor 558 to couple core 508 to sliding connector 528. Endcap 616 may be made of non-corrosive, electrically conducting materials such as nickel or stainless steel. Endcap 616 may be coupled to the end of insulated conductor 558 by any suitable method (for example, welding, soldering, braising). Sliding connector 528 may electrically couple core 508 and endcap 616 to ferromagnetic conductor 512. Conduit 518 may provide support for ferromagnetic conductor 512 at elevated temperatures.

[0819] FIG. 67 depicts a cross-sectional representation of an embodiment of a conductor-in-conduit temperature limited heater with an insulated conductor. Insulated conductor 558 includes core 508, electrical insulator 500, and jacket 506. Jacket 506 is made of a highly electrically conductive material such as copper. Core 508 is made of a lower temperature ferromagnetic material such as such as Alloy 42-6, Alloy 32, Invar 36, iron-nickel-chromium alloys, iron-nickel alloys, nickel alloys, or nickel-chromium alloys. In certain embodiments, the materials of jacket 506 and core 508 are reversed so that the jacket is the ferromagnetic conductor and the core is the highly conductive portion of the heater. Ferromagnetic material used in jacket 506 or core 508 may have a thickness greater than the skin depth at the Curie temperature (for example, 2 to 3 times the skin depth at the Curie temperature). Endcap 616 is placed at an end of insulated conductor 558 to couple core 508 to sliding connector 528. Endcap 616 is made of corrosion resistant, electrically conducting materials such as nickel or stainless steel. In certain embodiments, conduit 518 is a hollow sucker rod made from, for example, carbon steel.

[0820] In certain embodiments, a temperature limited heater includes a flexible cable (for example, a furnace cable) as the inner conductor. For example, the inner conductor may be a 27% nickel-clad or stainless steel-clad stranded copper wire with four layers of mica tape surrounded by a layer of ceramic and/or mineral fiber (for example, alumina fiber, aluminosilicate fiber, borosilicate fiber, or aluminoborosilicate fiber). A stainless steel-clad stranded copper wire furnace cable may be available from Anomet Products, Inc. The inner

conductor may be rated for applications at temperatures of 1000 °C or higher. The inner conductor may be pulled inside a conduit. The conduit may be a ferromagnetic conduit (for example, a ¾" Schedule 80 446 stainless steel pipe). The conduit may be covered with a layer of copper, or other electrical conductor, with a thickness of about 0.3 cm or any other suitable thickness. The assembly may be placed inside a support conduit (for example, a 1-¼" Schedule 80 347H or 347HH stainless steel tubular). The support conduit may provide additional creep-rupture strength and protection for the copper and the inner conductor. For uses at temperatures greater than about 1000 °C, the inner copper conductor may be plated with a more corrosion resistant alloy (for example, Incoloy® 825) to inhibit oxidation. In some embodiments, the top of the temperature limited heater is sealed to inhibit air from contacting the inner conductor.

[0821] The temperature limited heater may be a single-phase heater or a three-phase heater. In a three-phase heater embodiment, the temperature limited heater has a delta or a wye configuration. Each of the three ferromagnetic conductors in the three-phase heater may be inside a separate sheath. A connection between conductors may be made at the bottom of the heater inside a splice section. The three conductors may remain insulated from the sheath inside the splice section.

[0822] FIG. 68 depicts an embodiment of a three-phase temperature limited heater with ferromagnetic inner conductors. Each leg 618 has inner conductor 490, core 508, and jacket 506. Inner conductors 490 are ferritic stainless steel or 1% carbon steel. Inner conductors 490 have core 508. Core 508 may be copper. Each inner conductor 490 is coupled to its own jacket 506. Jacket 506 is a sheath made of a corrosion resistant material (such as 304H stainless steel). Electrical insulator 500 is placed between inner conductor 490 and jacket 506. Inner conductor 490 is ferritic stainless steel or carbon steel with an outside diameter of 1.14 cm and a thickness of 0.445 cm. Core 508 is a copper core with a 0.25 cm diameter. Each leg 618 of the heater is coupled to terminal block 620. Terminal block 620 is filled with insulation material 622 and has an outer surface of stainless steel. Insulation material 622 is, in some embodiments, silicon nitride, boron nitride, magnesium oxide or other suitable electrically insulating material. Inner conductors 490 of legs 618 are coupled (welded) in terminal block 620. Jackets 506 of legs 618 are coupled (welded) to an outer surface of terminal block 620. Terminal block 620 may include two halves coupled around the coupled portions of legs 618.

[0823] In some embodiments, the three-phase heater includes three legs that are located in separate wellbores. The legs may be coupled in a common contacting section (for example, a central wellbore, a connecting wellbore, or a solution filled contacting section). FIG. 69 depicts an embodiment of temperature limited heaters coupled in a three-phase configuration. Each leg 624, 626, 628 may be located in separate openings 522 in hydrocarbon layer 460. Each leg 624,

626, 628 may include heating element 630. Each leg 624, 626, 628 may be coupled to single contacting element 632 in one opening 522. Contacting element 632 may electrically couple legs 624, 626, 628 together in a three-phase configuration. Contacting element 632 may be located in, for example, a central opening in the formation. Contacting element 632 may be located in a portion of opening 522 below hydrocarbon layer 460 (for example, in the underburden). In certain embodiments, magnetic tracking of a magnetic element located in a central opening (for example, opening 522 of leg 626) is used to guide the formation of the outer openings (for example, openings 522 of legs 624 and 628) so that the outer openings intersect the central opening. The central opening may be formed first using standard wellbore drilling methods. Contacting element 632 may include funnels, guides, or catchers for allowing each leg to be inserted into the contacting element.

[0824] FIG. 70 depicts an embodiment of three heaters coupled in a three-phase configuration. Conductor "legs" 624, 626, 628 are coupled to three-phase transformer 634. Transformer 634 may be an isolated three-phase transformer. In certain embodiments, transformer 634 provides three-phase output in a wye configuration, as shown in FIG. 70. Input to transformer 634 may be made in any input configuration (such as the delta configuration shown in FIG. 70). Legs 624, 626, 628 each include lead-in conductors 636 in the overburden of the formation coupled to heating elements 630 in hydrocarbon layer 460. Lead-in conductors 636 include copper with an insulation layer. For example, lead-in conductors 636 may be a 4-0 copper cables with TEFLON® insulation, a copper rod with polyurethane insulation, or other metal conductors such as bare copper or aluminum. In certain embodiments, lead-in conductors 636 are located in an overburden portion of the formation. The overburden portion may include overburden casings 530. Heating elements 630 may be temperature limited heater heating elements. In an embodiment, heating elements 630 are 410 stainless steel rods (for example, 3.1 cm diameter 410 stainless steel rods). In some embodiments, heating elements 630 are composite temperature limited heater heating elements (for example, 347 stainless steel, 410 stainless steel, copper composite heating elements; 347 stainless steel, iron, copper composite heating elements; or 410 stainless steel and copper composite heating elements). In certain embodiments, heating elements 630 have a length of at least about 10 m to about 2000 m, about 20 m to about 400 m, or about 30 m to about 300 m.

[0825] In certain embodiments, heating elements 630 are exposed to hydrocarbon layer 460 and fluids from the hydrocarbon layer. Thus, heating elements 630 are "bare metal" or "exposed metal" heating elements. Heating elements 630 may be made from a material that has an acceptable sulfidation rate at high temperatures used for pyrolyzing hydrocarbons. In certain embodiments, heating elements 630 are made from material that has a sulfidation rate that

decreases with increasing temperature over at least a certain temperature range (for example, 500 °C to 650 °C, 530 °C to 650 °C, or 550 °C to 650 °C). For example, 410 stainless steel may have a sulfidation rate that decreases with increasing temperature between 530 °C and 650 °C. Using such materials reduces corrosion problems due to sulfur-containing gases (such as H_2S) from the formation. In certain embodiments, heating elements 630 are made from material that has a sulfidation rate below a selected value in a temperature range. In some embodiments, heating elements 630 are made from material that has a sulfidation rate at most about 25 mils per year at a temperature between about 800 °C and about 880 °C. In some embodiments, the sulfidation rate is at most about 35 mils per year at a temperature between about 800 °C and about 880 °C, at most about 45 mils per year at a temperature between about 800 °C and about 880 °C, or at most about 55 mils per year at a temperature between about 800 °C and about 880 °C. Heating elements 630 may also be substantially inert to galvanic corrosion.

[0826] In some embodiments, heating elements 630 have a thin electrically insulating layer such as aluminum oxide or thermal spray coated aluminum oxide. In some embodiments, the thin electrically insulating layer is a ceramic composition such as an enamel coating. Enamel coatings include, but are not limited to, high temperature porcelain enamels. High temperature porcelain enamels may include silicon dioxide, boron oxide, alumina, and alkaline earth oxides (CaO or MgO), and minor amounts of alkali oxides (Na_2O, K_2O, LiO). The enamel coating may be applied as a finely ground slurry by dipping the heating element into the slurry or spray coating the heating element with the slurry. The coated heating element is then heated in a furnace until the glass transition temperature is reached so that the slurry spreads over the surface of the heating element and makes the porcelain enamel coating. The porcelain enamel coating contracts when cooled below the glass transition temperature so that the coating is in compression. Thus, when the coating is heated during operation of the heater, the coating is able to expand with the heater without cracking.

[0827] The thin electrically insulating layer has low thermal impedance allowing heat transfer from the heating element to the formation while inhibiting current leakage between heating elements in adjacent openings and/or current leakage into the formation. In certain embodiments, the thin electrically insulating layer is stable at temperatures above at least 350 °C, above 500 °C, or above 800 °C. In certain embodiments, the thin electrically insulating layer has an emissivity of at least 0.7, at least 0.8, or at least 0.9. Using the thin electrically insulating layer may allow for long heater lengths in the formation with low current leakage.

[0828] Heating elements 630 may be coupled to contacting elements 632 at or near the underburden of the formation. Contacting elements 632 are copper or aluminum rods or other highly conductive materials. In certain embodiments, transition sections 638 are located between

lead-in conductors 636 and heating elements 630, and/or between heating elements 630 and contacting elements 632. Transition sections 638 may be made of a conductive material that is corrosion resistant such as 347 stainless steel over a copper core. In certain embodiments, transition sections 638 are made of materials that electrically couple lead-in conductors 636 and heating elements 630 while providing little or no heat output. Thus, transition sections 638 help to inhibit overheating of conductors and insulation used in lead-in conductors 636 by spacing the lead-in conductors from heating elements 630. Transition section 638 may have a length of between about 3 m and about 9 m (for example, about 6 m).

[0829] Contacting elements 632 are coupled to contactor 640 in contacting section 642 to electrically couple legs 624, 626, 628 to each other. In some embodiments, contact solution 644 (for example, conductive cement) is placed in contacting section 642 to electrically couple contacting elements 632 in the contacting section. In certain embodiments, legs 624, 626, 628 are substantially parallel in hydrocarbon layer 460 and leg 624 continues substantially vertically into contacting section 642. The other two legs 626, 628 are directed (for example, by directionally drilling the wellbores for the legs) to intercept leg 624 in contacting section 642.

[0830] Each leg 624, 626, 628 may be one leg of a three-phase heater embodiment so that the legs are substantially electrically isolated from other heaters in the formation and are substantially electrically isolated from the formation. Legs 624, 626, 628 may be arranged in a triangular pattern so that the three legs form a triangular shaped three-phase heater. In an embodiment, legs 624, 626, 628 are arranged in a triangular pattern with 12 m spacing between the legs (each side of the triangle has a length of 12 m).

[0831] In certain embodiments, the thin electrically insulating layer allows for relatively long, substantially horizontal heater leg lengths in the hydrocarbon layer with a substantially u-shaped heater. FIG. 71 depicts a side-view representation of an embodiment of a substantially u-shaped three-phase heater. First ends of legs 624, 626, 628 are coupled to transformer 634 at first location 646. In an embodiment, transformer 634 is a three-phase AC transformer. Ends of legs 624, 626, 628 are electrically coupled together with connector 648 at second location 650. Connector 648 electrically couples the ends of legs 624, 626, 628 so that the legs can be operated in a three-phase configuration. In certain embodiments, legs 624, 626, 628 are coupled to operate in a three-phase wye configuration. In certain embodiments, legs 624, 626, 628 are substantially parallel in hydrocarbon layer 460. In certain embodiments, legs 624, 626, 628 are arranged in a triangular pattern in hydrocarbon layer 460. In certain embodiments, heating elements 630 include a thin electrically insulating material (such as a porcelain enamel coating) to inhibit current leakage from the heating elements. In certain embodiments, legs 624, 626, 628

are electrically coupled so that the legs are substantially electrically isolated from other heaters in the formation and are substantially electrically isolated from the formation.

[0832] In certain embodiments, overburden casings (for example, overburden casings 530, depicted in FIGS. 70 and 71) in overburden 458 include materials that inhibit ferromagnetic effects in the casings. Inhibiting ferromagnetic effects in casings 530 reduces heat losses to the overburden. In some embodiments, casings 530 may include non-metallic materials such as fiberglass, polyvinylchloride (PVC), chlorinated polyvinylchloride (CPVC), or high-density polyethylene (HDPE). HDPEs with working temperatures in a range for use in overburden 458 include HDPEs available from Dow Chemical Co., Inc. (Midland, Michigan, U.S.A.). A non-metallic casing may also eliminate the need for an insulated overburden conductor. In some embodiments, casings 530 include carbon steel coupled on the inside diameter of a non-ferromagnetic metal (for example, carbon steel clad with copper or aluminum) to inhibit ferromagnetic effects or inductive effects in the carbon steel. Other non-ferromagnetic metals include, but are not limited to, manganese steels with at least 10% by weight manganese, iron aluminum alloys with at least 18% by weight aluminum, and austentitic stainless steels such as 304 stainless steel or 316 stainless steel.

[0833] In certain embodiments, one or more non-ferromagnetic materials used in casings 530 are used in a wellhead coupled to the casings and legs 624, 626, 628. Using non-ferromagnetic materials in the wellhead inhibits undesirable heating of components in the wellhead. In some embodiments, a purge gas (for example, carbon dioxide, nitrogen or argon) is introduced into the wellhead and/or inside of casings 530 to inhibit reflux of heated gases into the wellhead and/or the casings.

[0834] In certain embodiments, one or more of legs 624, 626, 628 are installed in the formation using coiled tubing. In certain embodiments, coiled tubing is installed in the formation, the leg is installed inside the coiled tubing, and the coiled tubing is pulled out of the formation to leave the leg installed in the formation. The leg may be placed concentrically inside the coiled tubing. In some embodiments, coiled tubing with the leg inside the coiled tubing is installed in the formation and the coiled tubing is removed from the formation to leave the leg installed in the formation. The coiled tubing may extend only to a junction of hydrocarbon layer 460 and contacting section 642 or to a point at which the leg begins to bend in the contacting section.

[0835] FIG. 72 depicts a top view representation of an embodiment of a plurality of triads of three-phase heaters in the formation. Each triad 652 includes legs A, B, C (which may correspond to legs 624, 626, 628 depicted in FIGS. 70 and 71) that are electrically coupled by linkage 654. Each triad 652 is coupled to its own electrically isolated three-phase transformer so

that the triads are substantially electrically isolated from each other. Electrically isolating the triads inhibits net current flow between triads.

[0836] The phases of each triad 652 may be arranged so that legs A, B, C correspond between triads as shown in FIG. 72. In FIG. 72, legs A, B, C are arranged such that a phase leg (for example, leg A) in a given triad is about two triad heights from a same phase leg (leg A) in an adjacent triad. The triad height is the distance from a vertex of the triad to a midpoint of the line intersecting the other two vertices of the triad. In certain embodiments, the phases of triads 652 are arranged to inhibit net current flow between individual triads. There may be some leakage of current within an individual triad but little net current flows between two triads due to the substantial electrical isolation of the triads and, in certain embodiments, the arrangement of the triad phases.

[0837] In the early stages of heating, an exposed heating element (for example, heating element 630 depicted in FIGS. 70 and 71) may leak some current to water or other fluids that are electrically conductive in the formation so that the formation itself is heated. After water or other electrically conductive fluids are removed from the wellbore (for example, vaporized or produced), the heating elements become electrically isolated from the formation. Later, when water is removed from the formation, the formation becomes even more electrically resistant and heating of the formation occurs even more predominantly via thermally conductive and/or radiative heating. Typically, the formation (the hydrocarbon layer) has an initial electrical resistance that averages at least 10 ohm·m. In some embodiments, the formation has an initial electrical resistance of at least 100 ohm·m or of at least 300 ohm·m.

[0838] Using the temperature limited heaters as the heating elements limits the effect of water saturation on heater efficiency. With water in the formation and in heater wellbores, there is a tendency for electrical current to flow between heater elements at the top of the hydrocarbon layer where the voltage is highest and cause uneven heating in the hydrocarbon layer. This effect is inhibited with temperature limited heaters because the temperature limited heaters reduce localized overheating in the heating elements and in the hydrocarbon layer.

[0839] In certain embodiments, production wells are placed at a location at which there is relatively little or zero voltage potential. This location minimizes stray potentials at the production well. Placing production wells at such locations improves the safety of the system and reduces or inhibits undesired heating of the production wells caused by electrical current flow in the production wells. FIG. 73 depicts a top view representation of the embodiment depicted in FIG. 72 with production wells 206. In certain embodiments, production wells 206 are located at or near center of triad 652. In certain embodiments, production wells 206 are placed at a location between triads at which there is relatively little or zero voltage potential (at a location

at which voltage potentials from vertices of three triads average out to relatively little or zero voltage potential). For example, production well 206 may be at a location equidistant from legs A of one triad, leg B of a second triad, and leg C of a third triad, as shown in FIG. 73.

[0840] FIG. 74 depicts a top view representation of an embodiment of a plurality of triads of three-phase heaters in a hexagonal pattern in the formation. FIG. 75 depicts a top view representation of an embodiment of a hexagon from FIG. 74. Hexagon 656 includes two triads of heaters. The first triad includes legs A1, B1, C1 electrically coupled together by linkages 654 in a three-phase configuration. The second triad includes legs A2, B2, C2 electrically coupled together by linkages 654 in a three-phase configuration. The triads are arranged so that corresponding legs of the triads (for example, A1 and A2, B1 and B2, C1 and C2) are at opposite vertices of hexagon 656. The triads are electrically coupled and arranged so that there is relatively little or zero voltage potential at or near the center of hexagon 656.

[0841] Production well 206 may be placed at or near the center of hexagon 656. Placing production well 206 at or near the center of hexagon 656 places the production well at a location that reduces or inhibits undesired heating due to electromagnetic effects caused by electrical current flow in the legs of the triads and increases the safety of the system. Having two triads in hexagon 656 provides for redundant heating around production well 206. Thus, if one triad fails or has to be turned off, production well 206 still remains at a center of one triad.

[0842] As shown in FIG. 74, hexagons 656 may be arranged in a pattern in the formation such that adjacent hexagons are offset. Using electrically isolated transformers on adjacent hexagons may inhibit electrical potentials in the formation so that little or no net current leaks between hexagons.

[0843] Triads of heaters and/or heater legs may be arranged in any shape or desired pattern. For example, as described above, triads may include three heaters and/or heater legs arranged in an equilateral triangular pattern. In some embodiments, triads include three heaters and/or heater legs arranged in other triangular shapes (for example, an isosceles triangle or a right angle triangle). In some embodiments, heater legs in the triad cross each other (for example, criss-cross) in the formation. In certain embodiments, triads includes three heaters and/or heater legs arranged sequentially along a straight line.

[0844] FIG. 76 depicts an embodiment with triads coupled to a horizontal connector well. Triad 652A includes legs 624A, 626A, 628A. Triad 652B includes legs 624B, 626B, 628B. Legs 624A, 626A, 628A and legs 624B, 626B, 628B may be arranged along a straight line on the surface of the formation. In some embodiments, legs 624A, 626A, 628A are arranged along a straight line and offset from legs 624B, 626B, 628B, which may be arranged along a straight line. Legs 624A, 626A, 628A and legs 624B, 626B, 628B include heating elements 630 located in

hydrocarbon layer 460. Lead-in conductors 636 couple heating elements 630 to the surface of the formation. Heating elements 630 are coupled to contacting elements 632 at or near the underburden of the formation. In certain embodiments, transition sections (for example, transition sections 638 depicted in FIG. 70) are located between lead-in conductors 636 and heating elements 630, and/or between heating elements 630 and contacting elements 632.

[0845] Contacting elements 632 are coupled to contactor 640 in contacting section 642 to electrically couple legs 624A, 626A, 628A to each other to form triad 652A and electrically couple legs 624B, 626B, 628B to each other to form triad 652B. In certain embodiments, contactor 640 is a ground conductor so that triad 652A and/or triad 652B may be coupled in three-phase wye configurations. In certain embodiments, triad 652A and triad 652B are electrically isolated from each other. In some embodiments, triad 652A and triad 652B are electrically coupled to each other (for example, electrically coupled in series or parallel).

[0846] In certain embodiments, contactor 640 is a substantially horizontal contactor located in contacting section 642. Contactor 640 may be a casing or a solid rod placed in a wellbore drilled substantially horizontally in contacting section 642. Legs 624A, 626A, 628A and legs 624B, 626B, 628B may be electrically coupled to contactor 640 by any method described herein or any method known in the art. For example, containers with thermite powder are coupled to contactor 640 (for example, by welding or brazing the containers to the contactor); legs 624A, 626A, 628A and legs 624B, 626B, 628B are placed inside the containers; and the thermite powder is activated to electrically couple the legs to the contactor. The containers may be coupled to contactor 640 by, for example, placing the containers in holes or recesses in contactor 640 or coupled to the outside of the contactor and then brazing or welding the containers to the contactor.

[0847] As shown in FIG. 70, contacting elements 632 of legs 624, 626, 628 may be coupled using contactor 640 and/or contact solution 644. In certain embodiments, contacting elements 632 of legs 624, 626, 628 are physically coupled, for example, through soldering, welding, or other techniques. FIGS. 77 and 78 depict embodiments for coupling contacting elements 632 of legs 624, 626, 628. Legs 626, 628 may enter the wellbore of leg 624 from any direction desired. In one embodiment, legs 626, 628 enter the wellbore of leg 624 from approximately the same side of the wellbore, as shown in FIG. 77. In an alternative embodiment, legs 626, 628 enter the wellbore of leg 624 from approximately opposite sides of the wellbore, as shown in FIG. 78.

[0848] Container 658 is coupled to contacting element 632 of leg 624. Container 658 may be soldered, welded, or otherwise electrically coupled to contacting element 632. Container 658 is a metal can or other container with at least one opening for receiving one or more contacting elements 632. In an embodiment, container 658 is a can that has an opening for receiving contacting elements 632 from legs 626, 628, as shown in FIG. 77. In certain embodiments,

wellbores for legs 626, 628 are drilled parallel to the wellbore for leg 624 through the hydrocarbon layer that is to be heated and directionally drilled below the hydrocarbon layer to intercept wellbore for leg 624 at an angle between about 10° and about 20° from vertical. Wellbores may be directionally drilled using known techniques such as techniques used by Vector Magnetics, Inc.

[0849] In some embodiments, contacting elements 632 contact the bottom of container 658. Contacting elements 632 may contact the bottom of container 658 and/or each other to promote electrical connection between the contacting elements and/or the container. In certain embodiments, end portions of contacting elements 632 are annealed to a "dead soft" condition to facilitate entry into container 658. In some embodiments, rubber or other softening material is attached to end portions of contacting elements 632 to facilitate entry into container 658. In some embodiments, contacting elements 632 include reticulated sections, such as knuckle-joints or limited rotation knuckle-joints, to facilitate entry into container 658.

[0850] In certain embodiments, an electrical coupling material is placed in container 658. The electrical coupling material may line the walls of container 658 or fill up a portion of the container. In certain embodiments, the electrical coupling material lines an upper portion, such as the funnel-shaped portion shown in FIG. 79, of container 658. The electrical coupling material includes one or more materials that when activated (for example, heated, ignited, exploded, combined, mixed, and/or reacted) form a material that electrically couples one or more elements to each other. In an embodiment, the coupling material electrically couples contacting elements 632 in container 658. In some embodiments, the coupling material metallically bonds to contacting elements 632 so that the contacting elements are metallically bonded to each other. In some embodiments, container 658 is initially filled with a high viscosity water-based polymer fluid to inhibit drill cuttings or other materials from entering the container prior to using the coupling material to couple the contacting elements. The polymer fluid may be, but is not limited to, a cross-linked XC polymer (available from Baroid Industrial Drilling Products (Houston, Texas, U.S.A.), a frac gel, or a cross-linked polyacrylamide gel.

[0851] In certain embodiments, the electrical coupling material is a low-temperature solder that melts at relatively low temperature and when cooled forms an electrical connection to exposed metal surfaces. In certain embodiments, the electrical coupling material is a solder that melts at a temperature below the boiling point of water at the depth of container 658. In one embodiment, the electrical coupling material is a 58% by weight bismuth and 42% by weight tin eutectic alloy. Other examples of such solders include, but are not limited to, a 54% by weight bismuth, 16% by weight tin, 30% by weight indium alloy, and a 48% by weight tin, 52% by weight indium alloy. Such low-temperature solders will displace water upon melting so that the water moves to the top

of container 658. Water at the top of container 658 may inhibit heat transfer into the container and thermally insulate the low-temperature solder so that the solder remains at cooler temperatures and does not melt during heating of the formation using the heating elements.

[0852] Container 658 may be heated to activate the electrical coupling material to facilitate the connection of contacting elements 632. In certain embodiments, container 658 is heated to melt the electrical coupling material in the container. The electrical coupling material flows when melted and surrounds contacting elements 632 in container 658. Any water within container 658 will float to the surface of the metal when the metal is melted. The electrical coupling material is allowed to cool and electrically connects contacting elements 632 to each other. In certain embodiments, contacting elements 632 of legs 626, 628, the inside walls of container 658, and/or the bottom of the container are initially pre-tinned with electrical coupling material.

[0853] End portions of contacting elements 632 of legs 624, 626, 628 may have shapes and/or features that enhance the electrical connection between the contacting elements and the coupling material. The shapes and/or features of contacting elements 632 may also enhance the physical strength of the connection between the contacting elements and the coupling material (for example, the shape and/or features of the contacting element may anchor the contacting element in the coupling material). Shapes and/or features for end portions of contacting elements 632 include, but are not limited to, grooves, notches, holes, threads, serrated edges, openings, and hollow end portions. In certain embodiments, the shapes and/or features of the end portions of contacting elements 632 are initially pre-tinned with electrical coupling material.

[0854] FIG. 79 depicts an embodiment of container 658 with an initiator for melting the coupling material. The initiator is an electrical resistance heating element or any other element for providing heat that activates or melts the coupling material in container 658. In certain embodiments, heating element 660 is a heating element located in the walls of container 658. In some embodiments, heating element 660 is located on the outside of container 658. Heating element 660 may be, for example, a nichrome wire, a mineral-insulated conductor, a polymer-insulated conductor, a cable, or a tape that is inside the walls of container 658 or on the outside of the container. In some embodiments, heating element 660 wraps around the inside walls of the container or around the outside of the container. Lead-in wire 662 may be coupled to a power source at the surface of the formation. Lead-out wire 664 may be coupled to the power source at the surface of the formation. Lead-in wire 662 and/or lead-out wire 664 may be coupled along the length of leg 624 for mechanical support. Lead-in wire 662 and/or lead-out wire 664 may be removed from the wellbore after melting the coupling material. Lead-in wire 662 and/or lead-out wire 664 may be reused in other wellbores.

[0855] In some embodiments, container 658 has a funnel-shape, as shown in FIG. 79, that facilitates the entry of contacting elements 632 into the container. In certain embodiments, container 658 is made of or includes copper for good electrical and thermal conductivity. A copper container 658 makes good electrical contact with contacting elements (such as contacting elements 632 shown in FIGS. 77 and 78) if the contacting elements touch the walls and/or bottom of the container.

[0856] FIG. 80 depicts an embodiment of container 658 with bulbs on contacting elements 632. Protrusions 666 may be coupled to a lower portion of contacting elements 632. Protrusions 668 may be coupled to the inner wall of container 658. Protrusions 666, 668 may be made of copper or another suitable electrically conductive material. Lower portion of contacting element 632 of leg 628 may have a bulbous shape, as shown in FIG. 80. In certain embodiments, contacting element 632 of leg 628 is inserted into container 658. Contacting element 632 of leg 626 is inserted after insertion of contacting element 632 of leg 628. Both legs may then be pulled upwards simultaneously. Protrusions 666 may lock contacting elements 632 into place against protrusions 668 in container 658. A friction fit is created between contacting elements 632 and protrusions 666, 668.

[0857] Lower portions of contacting elements 632 inside container 658 may include 410 stainless steel or any other heat generating electrical conductor. Portions of contacting elements 632 above the heat generating portions of the contacting elements include copper or another highly electrically conductive material. Centralizers 524 may be located on the portions of contacting elements 632 above the heat generating portions of the contacting elements. Centralizers 524 inhibit physical and electrical contact of portions of contacting elements 632 above the heat generating portions of the contacting elements against walls of container 658.

[0858] When contacting elements 632 are locked into place inside container 658 by protrusions 666, 668, at least some electrical current may be pass between the contacting elements through the protrusions. As electrical current is passed through the heat generating portions of contacting elements 632, heat is generated in container 658. The generated heat may melt coupling material 670 located inside container 658. Water in container 658 may boil. The boiling water may convect heat to upper portions of container 658 and aid in melting of coupling material 670. Walls of container 658 may be thermally insulated to reduce heat losses out of the container and allow the inside of the container to heat up faster. Coupling material 670 flows down into the lower portion of container 658 as the coupling material melts. Coupling material 670 fills the lower portion of container 658 until the heat generating portions of contacting elements 632 are below the fill line of the coupling material. Coupling material 670 then electrically couples the portions of contacting elements 632 above the heat generating portions of the contacting

elements. The resistance of contacting elements 632 decreases at this point and heat is no longer generated in the contacting elements and the coupling materials is allowed to cool.

[0859] In certain embodiments, container 658 includes insulation layer 672 inside the housing of the container. Insulation layer 672 may include thermally insulating materials to inhibit heat losses from the canister. For example, insulation layer 672 may include magnesium oxide, silicon nitride, or other thermally insulating materials that withstand operating temperatures in container 658. In certain embodiments, container 658 includes liner 674 on an inside surface of the container. Liner 674 may increase electrical conductivity inside container 658. Liner 674 may include electrically conductive materials such as copper or aluminum.

[0860] FIG. 81 depicts an alternative embodiment for container 658. Coupling material in container 658 includes powder 676. Powder 676 is a chemical mixture that produces a molten metal product from a reaction of the chemical mixture. In an embodiment, powder 676 is thermite powder. Powder 676 lines the walls of container 658 and/or is placed in the container. Igniter 678 is placed in powder 676. Igniter 678 may be, for example, a magnesium ribbon that when activated ignites the reaction of powder 676. When powder 676 reacts, a molten metal produced by the reaction flows and surrounds contacting elements 632 placed in container 658. When the molten metal cools, the cooled metal electrically connects contacting elements 632. In some embodiments, powder 676 is used in combination with another coupling material, such as a low-temperature solder, to couple contacting elements 632. The heat of reaction of powder 676 may be used to melt the low temperature-solder.

[0861] In certain embodiments, an explosive element is placed in container 658, depicted in FIG. 77 or FIG. 81. The explosive element may be, for example, a shaped charge explosive or other controlled explosive element. The explosive element may be exploded to crimp contacting elements 632 and/or container 658 together so that the contacting elements and the container are electrically connected. In some embodiments, an explosive element is used in combination with an electrical coupling material such as low-temperature solder or thermite powder to electrically connect contacting elements 632.

[0862] FIG. 82 depicts an alternative embodiment for coupling contacting elements 632 of legs 624, 626, 628. Container 658A is coupled to contacting element 632 of leg 626. Container 658B is coupled to contacting element 632 of leg 628. Container 658B is sized and shaped to be placed inside container 658A. Container 658C is coupled to contacting element 632 of leg 624. Container 658C is sized and shaped to be placed inside container 658B. In some embodiments, contacting element 632 of leg 624 is placed in container 658B without a container attached to the contacting element. One or more of containers 658A, 658B, 658C may be filled with a coupling

material that is activated to facilitate an electrical connection between contacting elements 632 as described above.

[0863] FIG. 83 depicts a side view representation of an embodiment for coupling contacting elements using temperature limited heating elements. Contacting elements 632 of legs 624, 626, 628 may have insulation 680 on portions of the contacting elements above container 658. Container 658 may be shaped and/or have guides at the top to guide the insertion of contacting elements 632 into the container. Coupling material 670 may be located inside container 658 at or near a top of the container. Coupling material 670 may be, for example, a solder material. In some embodiments, inside walls of container 658 are pre-coated with coupling material or another electrically conductive material such as copper or aluminum. Centralizers 524 may be coupled to contacting elements 632 to maintain a spacing of the contacting elements in container 658. Container 658 may be tapered at the bottom to push lower portions of contacting elements 632 together for at least some electrical contact between the lower portions of the contacting elements.

[0864] Heating elements 682 may be coupled to portions of contacting elements 632 inside container 658. Heating elements 682 may include ferromagnetic materials such as iron or stainless steel. In an embodiment, heating elements 682 are iron cylinders clad onto contacting elements 632. Heating elements 682 may be designed with dimensions and materials that will produce a desired amount of heat in container 658. In certain embodiments, walls of container 658 are thermally insulated with insulation layer 672, as shown in FIG. 83 to inhibit heat loss from the container. Heating elements 682 may be spaced so that contacting elements 632 have one or more portions of exposed material inside container 658. The exposed portions include exposed copper or another suitable highly electrically conductive material. The exposed portions allow for better electrical contact between contacting elements 632 and coupling material 670 after the coupling material has been melted, fills container 658, and is allowed to cool.

[0865] In certain embodiments, heating elements 682 operate as temperature limited heaters when a time-varying current is applied to the heating elements. For example, a 400 Hz, AC current may be applied to heating elements 682. Application of the time-varying current to contacting elements 632 causes heating elements 682 to generate heat and melt coupling material 670. Heating elements 682 may operate as temperature limited heating elements with a self-limiting temperature selected so that coupling material 670 is not overheated. As coupling material 670 fills container 658, the coupling material makes electrical contact between portions of exposed material on contacting elements 632 and electrical current begins to flow through the exposed material portions rather than heating elements 682. Thus, the electrical resistance between the contacting elements decreases. As this occurs, temperatures inside container 658

begin to decrease and coupling material 670 is allowed to cool to create an electrical contacting section between contacting elements 632. In certain embodiments, electrical power to contacting elements 632 and heating elements 682 is turned off when the electrical resistance in the system falls below a selected resistance. The selected resistance may indicate that the coupling material has sufficiently electrically connected the contacting elements. In some embodiments, electrical power is supplied to contacting elements 632 and heating elements 682 for a selected amount of time that is determined to provide enough heat to melt the mass of coupling material 670 provided in container 658.

[0866] FIG. 84 depicts a side view representation of an alternative embodiment for coupling contacting elements using temperature limited heating elements. Contacting element 632 of leg 624 may be coupled to container 658 by welding, brazing, or another suitable method. Lower portion of contacting element 632 of leg 628 may have a bulbous shape. Contacting element 632 of leg 628 is inserted into container 658. Contacting element 632 of leg 626 is inserted after insertion of contacting element 632 of leg 628. Both legs may then be pulled upwards simultaneously. Protrusions 668 may lock contacting elements 632 into place and a friction fit may be created between the contacting elements 632. Centralizers 524 may inhibit electrical contact between upper portions of contacting elements 632.

[0867] Time-varying electrical current may be applied to contacting elements 632 so that heating elements 682 generate heat. The generated heat may melt coupling material 670 located in container 658 and be allowed to cool, as described for the embodiment depicted in FIG. 83. After cooling of coupling material 670, contacting elements 632 of legs 626, 628, shown in FIG. 84, are electrically coupled in container 658 with the coupling material. In some embodiments, lower portions of contacting elements 632 have protrusions or openings that anchor the contacting elements in cooled coupling material. Exposed portions of the contacting elements provide a low electrical resistance path between the contacting elements and the coupling material.

[0868] FIG. 85 depicts a side view representation of another embodiment for coupling contacting elements using temperature limited heating elements. Contacting element 632 of leg 624 may be coupled to container 658 by welding, brazing, or another suitable method. Lower portion of contacting element 632 of leg 628 may have a bulbous shape. Contacting element 632 of leg 628 is inserted into container 658. Contacting element 632 of leg 626 is inserted after insertion of contacting element 632 of leg 628. Both legs may then be pulled upwards simultaneously. Protrusions 668 may lock contacting elements 632 into place and a friction fit may be created between the contacting elements 632. Centralizers 524 may inhibit electrical contact between upper portions of contacting elements 632.

[0869] End portions 632B of contacting elements 632 may be made of a ferromagnetic material such as 410 stainless steel. Portions 632A may include non-ferromagnetic electrically conductive material such as copper or aluminum. Time-varying electrical current may be applied to contacting elements 632 so that end portions 632B generate heat due to the resistance of the end portions. The generated heat may melt coupling material 670 located in container 658 and be allowed to cool, as described for the embodiment depicted in FIG. 83. After cooling of coupling material 670, contacting elements 632 of legs 626, 628, shown in FIG. 84, are electrically coupled in container 658 with the coupling material. Portions 632A may be below the fill line of coupling material 670 so that these portions of the contacting elements provide a low electrical resistance path between the contacting elements and the coupling material.

[0870] FIG. 86 depicts a side view representation of an alternative embodiment for coupling contacting elements of three legs of a heater. FIG. 87 depicts a top view representation of the alternative embodiment for coupling contacting elements of three legs of a heater depicted in FIG. 86. Container 658 may include inner container 684 and outer container 686. Inner container 684 may be made of copper or another malleable, electrically conductive metal such as aluminum. Outer container 686 may be made of a rigid material such as stainless steel. Outer container 686 protects inner container 684 and its contents from environmental conditions outside of container 658.

[0871] Inner container 684 may be substantially solid with two openings 688 and 690. Inner container 684 is coupled to contacting element 632 of leg 624. For example, inner container 684 may be welded or brazed to contacting element 632 of leg 624. Openings 688, 690 are shaped to allow contacting elements 632 of legs 626, 628 to enter the openings as shown in FIG. 86. Funnels or other guiding mechanisms may be coupled to the entrances to openings 688, 690 to guide contacting elements 632 of legs 626, 628 into the openings. Contacting elements 632 of legs 624, 626, 628 may be made of the same material as inner container 684.

[0872] Explosive elements 700 may be coupled to the outer wall of inner container 684. In certain embodiments, explosive elements 700 are elongated explosive strips that extend along the outer wall of inner container 684. Explosive elements 700 may be arranged along the outer wall of inner container 684 so that the explosive elements are aligned at or near the centers of contacting elements 632, as shown in FIG. 87. Explosive elements 700 are arranged in this configuration so that energy from the explosion of the explosive elements causes contacting elements 632 to be pushed towards the center of inner container 684.

[0873] Explosive elements 700 may be coupled to battery 702 and timer 704. Battery 702 may provide power to explosive elements 700 to initiate the explosion. Timer 704 may be used to control the time for igniting explosive elements 700. Battery 702 and timer 704 may be coupled

to triggers 706. Triggers 706 may be located in openings 688, 690. Contacting elements 632 may set off triggers 706 as the contacting elements are placed into openings 688, 690. When both triggers 706 in openings 688, 690 are triggered, timer 704 may initiate a countdown before igniting explosive elements 700. Thus, explosive elements 700 are controlled to explode only after contacting elements 632 are placed sufficiently into openings 688, 690 so that electrical contact may be made between the contacting elements and inner container 684 after the explosions. Explosion of explosive elements 700 crimps contacting elements 632 and inner container 684 together to make electrical contact between the contacting elements and the inner container. In certain embodiments, explosive elements 700 fire from the bottom towards the top of inner container 684. Explosive elements 700 may be designed with a length and explosive power (band width) that gives an optimum electrical contact between contacting elements 632 and inner container 684.

[0874] In some embodiments, triggers 706, battery 702, and timer 704 may be used to ignite a powder (for example, copper thermite powder) inside a container (for example, container 658 or inner container 684). Battery 702 may charge a magnesium ribbon or other ignition device in the powder to initiate reaction of the powder to produce a molten metal product. The molten metal product may flow and then cool to electrically contact the contacting elements.

[0875] In certain embodiments, electrical connection is made between contacting elements 632 through mechanical means. FIG. 88 depicts an embodiment of contacting element 632 with a brush contactor. Brush contactor 708 is coupled to a lower portion of contacting element 632. Brush contactor 708 may be made of a malleable, electrically conductive material such as copper or aluminum. Brush contactor 708 may be a webbing of material that is compressible and/or flexible. Centralizer 524 may be located at or near the bottom of contacting element 632.

[0876] FIG. 89 depicts an embodiment for coupling contacting elements 632 with brush contactors 708. Brush contactors 708 are coupled to each contacting element 632 of legs 624, 626, 628. Brush contactors 708 compress against each other and interlace to electrically couple contacting elements 632 of legs 624, 626, 628. Centralizers 524 maintain spacing between contacting elements 632 of legs 624, 626, 628 so that interference and/or clearance issues between the contacting elements are inhibited.

[0877] In certain embodiments, contacting elements 632 (depicted in FIGS. 77-89) are coupled in a zone of the formation that is cooler than the layer of the formation to be heated (for example, in the underburden of the formation). Contacting elements 632 are coupled in a cooler zone to inhibit melting of the coupling material and/or degradation of the electrical connection between the elements during heating of the hydrocarbon layer above the cooler zone. In certain embodiments, contacting elements 632 are coupled in a zone that is at least about 3 m, at least

about 6 m, or at least about 9 m below the layer of the formation to be heated. In some embodiments, the zone has a standing water level that is above a depth of containers 658.

[0878] In certain embodiments, two legs in separate wellbores intercept in a single contacting section. FIG. 90 depicts an embodiment of two temperature limited heaters coupled in a single contacting section. Legs 624 and 626 include one or more heating elements 630. Heating elements 630 may include one or more electrical conductors. In certain embodiments, legs 624 and 626 are electrically coupled in a single-phase configuration with one leg positively biased versus the other leg so that current flows downhole through one leg and returns through the other leg.

[0879] Heating elements 630 in legs 624 and 626 may be temperature limited heaters. In certain embodiments, heating elements 630 are solid rod heaters. For example, heating elements 630 may be rods made of a single ferromagnetic conductor element or composite conductors that include ferromagnetic material. During initial heating when water is present in the formation being heated, heating elements 630 may leak current into hydrocarbon layer 460. The current leaked into hydrocarbon layer 460 may resistively heat the hydrocarbon layer.

[0880] In some embodiments (for example, in oil shale formations), heating elements 630 do not need support members. Heating elements 630 may be partially or slightly bent, curved, made into an S-shape, or made into a helical shape to allow for expansion and/or contraction of the heating elements. In certain embodiments, solid rod heating elements 630 are placed in small diameter wellbores (for example, about 3 ¾" (about 9.5 cm) diameter wellbores). Small diameter wellbores may be less expensive to drill or form than larger diameter wellbores, and there will be less cuttings to dispose of.

[0881] In certain embodiments, portions of legs 624 and 626 in overburden 458 have insulation (for example, polymer insulation) to inhibit heating the overburden. Heating elements 630 may be substantially vertical and substantially parallel to each other in hydrocarbon layer 460. At or near the bottom of hydrocarbon layer 460, leg 624 may be directionally drilled towards leg 626 to intercept leg 626 in contacting section 642. Drilling two wellbores to intercept each other may be easier and less expensive than drilling three or more wellbores to intercept each other. The depth of contacting section 642 depends on the length of bend in leg 624 needed to intercept leg 626. For example, for a 40 ft (about 12 m) spacing between vertical portions of legs 624 and 626, about 200 ft (about 61 m) is needed to allow the bend of leg 624 to intercept leg 626. Coupling two legs may require a thinner contacting section 642 than coupling three or more legs in the contacting section.

[0882] FIG. 91 depicts an embodiment for coupling legs 624 and 626 in contacting section 642. Heating elements 630 are coupled to contacting elements 632 at or near junction of contacting

section 642 and hydrocarbon layer 460. Contacting elements 632 may be copper or another suitable electrical conductor. In certain embodiments, contacting element 632 in leg 626 is a liner with opening 710. Contacting element 632 from leg 624 passes through opening 710. Contactor 640 is coupled to the end of contacting element 632 from leg 624. Contactor 640 provides electrical coupling between contacting elements in legs 624 and 626.

[0883] In certain embodiments, contacting elements 632 include one or more fins or projections. The fins or projections may increase an electrical contact area of contacting elements 632. In some embodiments, contacting element 632 of leg 626 has an opening or other orifice that allows the contacting element of 624 to couple to the contacting element of leg 626.

[0884] In certain embodiments, legs 624 and 626 are coupled together to form a diad. Three diads may be coupled to a three-phase transformer to power the legs of the heaters. FIG. 92 depicts an embodiment of three diads coupled to a three-phase transformer. In certain embodiments, transformer 634 is a delta three-phase transformer. Diad 712A includes legs 624A and 626A. Diad 712B includes legs 624B and 626B. Diad 712C includes legs 624C and 626C. Diads 712A, 712B, 712C are coupled to the secondaries of transformer 634. Diad 712A is coupled to the "A" secondary. Diad 712B is coupled to the "B" secondary. Diad 712C is coupled to the "C" secondary.

[0885] Coupling the diads to the secondaries of the delta three-phase transformer isolates the diads from ground. Isolating the diads from ground inhibits leakage to the formation from the diads. Coupling the diads to different phases of the delta three-phase transformer also inhibits leakage between the heating legs of the diads in the formation.

[0886] In some embodiments, diads are used for treating formations using triangular or hexagonal heater patterns. FIG. 93 depicts an embodiment of groups of diads in a hexagonal pattern. Heaters may be placed at the vertices of each of the hexagons in the hexagonal pattern. Each group 714 of diads (enclosed by dashed circles) may be coupled to a separate three-phase transformer. "A", "B", and "C" inside groups 714 represent each diad (for example, diads 712A, 712B, 712C depicted in FIG. 92) that is coupled to each of the three secondary phases of the transformer with each phase coupled to one diad (with the heaters at the vertices of the hexagon). The numbers "1", "2", and "3" inside the hexagons represent the three repeating types of hexagons in the pattern depicted in FIG. 93.

[0887] FIG. 94 depicts an embodiment of diads in a triangular pattern. Three diads 712A, 712B, 712C may be enclosed in each group 714 of diads (enclosed by dashed rectangles). Each group 714 may be coupled to a separate three-phase transformer.

[0888] In certain embodiments, exposed metal heating elements are used in substantially horizontal sections of u-shaped wellbores. Substantially u-shaped wellbores may be used in tar

sands formations, oil shale formation, or other formations with relatively thin hydrocarbon layers. Tar sands or thin oil shale formations may have thin shallow layers that are more easily and uniformly heated using heaters placed in substantially u-shaped wellbores. Substantially u-shaped wellbores may also be used to process formations with thick hydrocarbon layers in formations. In some embodiments, substantially u-shaped wellbores are used to access rich layers in a thick hydrocarbon formation.

[0889] Heaters in substantially u-shaped wellbores may have long lengths compared to heaters in vertical wellbores because horizontal heating sections do not have problems with creep or hanging stress encountered with vertical heating elements. Substantially u-shaped wellbores may make use of natural seals in the formation and/or the limited thickness of the hydrocarbon layer. For example, the wellbores may be placed above or below natural seals in the formation without punching large numbers of holes in the natural seals, as would be needed with vertically oriented wellbores. Using substantially u-shaped wellbores instead of vertical wellbores may also reduce the number of wells needed to treat a surface footprint of the formation. Using less wells reduces capital costs for equipment and reduces the environmental impact of treating the formation by reducing the amount of wellbores on the surface and the amount of equipment on the surface. Substantially u-shaped wellbores may also utilize a lower ratio of overburden section to heated section than vertical wellbores.

[0890] Substantially u-shaped wellbores may allow for flexible placement of opening of the wellbores on the surface. Openings to the wellbores may be placed according to the surface topology of the formation. In certain embodiments, the openings of wellbores are placed at geographically accessible locations such as topological highs (for examples, hills). For example, the wellbore may have a first opening on a first topologic high and a second opening on a second topologic high and the wellbore crosses beneath a topologic low (for example, a valley with alluvial fill) between the first and second topologic highs. This placement of the openings may avoid placing openings or equipment in topologic lows or other inaccessible locations. In addition, the water level may not be artesian in topologically high areas. Wellbores may be drilled so that the openings are not located near environmentally sensitive areas such as, but not limited to, streams, nesting areas, or animal refuges.

[0891] FIG. 95 depicts a side-view representation of an embodiment of a heater with an exposed metal heating element placed in a substantially u-shaped wellbore. Heaters 716A, 716B, 716C have first end portions at first location 646 on surface 534 of the formation and second end portions at second location 650 on the surface. Heaters 716A, 716B, 716C have sections 718 in overburden 458. Sections 718 are configured to provide little or no heat output. In certain

embodiments, sections 718 include an insulated electrical conductor such as insulated copper. Sections 718 are coupled to heating elements 630.

[0892] In certain embodiments, portions of heating elements 630 are substantially parallel in hydrocarbon layer 460. In certain embodiments, heating elements 630 are exposed metal heating elements. In certain embodiments, heating elements 630 are exposed metal temperature limited heating elements. Heating elements 630 may include ferromagnetic materials such as 9% by weight to 13% by weight chromium stainless steel like 410 stainless steel, chromium stainless steels such as T/P91 or T/P92, 409 stainless steel, VM12 (Vallourec and Mannesmann Tubes, France) or iron-cobalt alloys for use as temperature limited heaters. In some embodiments, heating elements 630 are composite temperature limited heating elements such as 410 stainless steel and copper composite heating elements or 347H, iron, copper composite heating elements. Heating elements 630 may have lengths of at least about 100 m, at least about 500 m, or at least about 1000 m, up to lengths of about 6000 m.

[0893] Heating elements 630 may be solid rods or tubulars. In certain embodiments, solid rod heating elements have diameters several times the skin depth at the Curie temperature of the ferromagnetic material. Typically, the solid rod heating elements may have diameters of 1.91 cm or larger (for example, 2.5 cm, 3.2 cm, 3.81 cm, or 5.1 cm). In certain embodiments, tubular heating elements have wall thicknesses of at least twice the skin depth at the Curie temperature of the ferromagnetic material. Typically, the tubular heating elements have outside diameters of between about 2.5 cm and about 15.2 cm and wall thickness in range between about 0.13 cm and about 1.01 cm.

[0894] In certain embodiments, tubular heating elements 630 allow fluids to be convected through the tubular heating elements. Fluid flowing through the tubular heating elements may be used to preheat the tubular heating elements, to initially heat the formation, and/or to recover heat from the formation after heating is completed for the in situ heat treatment process. Fluids that may be flow through the tubular heating elements include, but are not limited to, air, water, steam, helium, carbon dioxide or other fluids. In some embodiments, a hot fluid, such as carbon dioxide or helium, flows through the tubular heating elements to provide heat to the formation. The hot fluid may be used to provide heat to the formation before electrical heating is used to provide heat to the formation. In some embodiments, the hot fluid is used to provide heat in addition to electrical heating. Using the hot fluid to provide heat to the formation in addition to providing electrical heating may be less expensive than using electrical heating alone to provide heat to the formation. In some embodiments, water and/or steam flows through the tubular heating element to recover heat from the formation. The heated water and/or steam may be used for solution mining and/or other processes.

[0895] Transition sections 720 may couple heating elements 630 to sections 718. In certain embodiments, transition sections 720 include material that has a high electrical conductivity but is corrosion resistant, such as 347 stainless steel over copper. In an embodiment, transition sections include a composite of stainless steel clad over copper. Transition sections 720 inhibit overheating of copper and/or insulation in sections 718.

[0896] FIG. 96 depicts a representational top view of an embodiment of a surface pattern of heaters depicted in FIG. 95. Heaters 716A-L may be arranged in a repeating triangular pattern on the surface of the formation, as shown in FIG. 96. A triangle may be formed by heaters 716A, 716B, and 716C and a triangle formed by heaters 716C, 716D, and 716E. In some embodiments, heaters 716A-L are arranged in a straight line on the surface of the formation. Heaters 716A-L have first end portions at first location 646 on the surface and second end portions at second location 650 on the surface. Heaters 716A-L are arranged such that (a) the patterns at first location 646 and second location 650 correspond to each other, (b) the spacing between heaters is maintained at the two locations on the surface, and/or (c) the heaters all have substantially the same length (substantially the same horizontal distance between the end portions of the heaters on the surface as shown in the top view of FIG. 96).

[0897] As depicted in FIGS. 95 and 96, cables 722, 724 may be coupled to transformer 728 and one or more heater units, such as the heater unit including heaters 716A, 716B, 716C. Cables 722, 724 may carry a large amount of power. In certain embodiments, cables 722, 724 are capable of carrying high currents with low losses. For example, cables 722, 724 may be thick copper or aluminum conductors. The cables may also have thick insulation layers. In some embodiments, cable 722 and/or cable 724 may be superconducting cables. The superconducting cables may be cooled by liquid nitrogen. Superconducting cables are available from Superpower, Inc. (Schenectady, New York, U.S.A.). Superconducting cables may minimize power loss and reduce the size of the cables needed to couple transformer 728 to the heaters. In some embodiments, cables 722, 724 may be made of carbon nanotubes. Carbon nanotubes as conductors may have about 1000 times the conductivity of copper for the same diameter. Also, carbon nanotubes may not require refrigeration during use.

[0898] In certain embodiments, bus bar 726A is coupled to first end portions of heaters 716A-L and bus bar 726B is coupled to second end portions of heaters 716A-L. Bus bars 726A,B electrically couple heaters 716A-L to cables 722, 724 and transformer 728. Bus bars 726A,B distribute power to heaters 716A-L. In certain embodiments, bus bars 726A,B are capable of carrying high currents with low losses. In some embodiments, bus bars 726A,B are made of superconducting material such as the superconductor material used in cables 722, 724. In some embodiments, bus bars 726A,B may include carbon nanotube conductors.

[0899] As shown in FIGS. 95 and 96, heaters 716A-L are coupled to a single transformer 728. In certain embodiments, transformer 728 is a source of time-varying current. In certain embodiments, transformer 728 is an electrically isolated, single-phase transformer. In certain embodiments, transformer 728 provides power to heaters 716A-L from an isolated secondary phase of the transformer. First end portions of heaters 716A-L may be coupled to one side of transformer 728 while second end portions of the heaters are coupled to the opposite side of the transformer. Transformer 728 provides a substantially common voltage to the first end portions of heaters 716A-L and a substantially common voltage to the second end portions of heaters 716A-L. In certain embodiments, transformer 728 applies a voltage potential to the first end portions of heaters 716A-L that is opposite in polarity and substantially equal in magnitude to a voltage potential applied to the second end portions of the heaters. For example, a +660 V potential may be applied to the first end portions of heaters 716A-L and a -660 V potential applied to the second end portions of the heaters at a selected point on the wave of time-varying current (such as AC or modulated DC). Thus, the voltages at the two end portion of the heaters may be equal in magnitude and opposite in polarity with an average voltage that is substantially at ground potential.

[0900] Applying the same voltage potentials to the end portions of all heaters 716A-L produces voltage potentials along the lengths of the heaters that are substantially the same along the lengths of the heaters. FIG. 97 depicts a cross-section representation, along a vertical plane, such as the plane A-A shown in FIG. 95, of substantially u-shaped heaters in a hydrocarbon layer. The voltage potential at the cross-sectional point shown in FIG. 97 along the length of heater 716A is substantially the same as the voltage potential at the corresponding cross-sectional points on heaters 716A-L shown in FIG. 97. At lines equidistant between heater wellheads, the voltage potential is approximately zero. Other wells, such as production wells or monitoring wells, may be located along these zero voltage potential lines, if desired. Production wells 206 located close to the overburden may be used to transport formation fluid that is initially in a vapor phase to the surface. Production wells located close to a bottom of the heated portion of the formation may be used to transport formation fluid that is initially in a liquid phase to the surface.

[0901] In certain embodiments, the voltage potential at the midpoint of heaters 716A-L is about zero. Having similar voltage potentials along the lengths of heaters 716A-L inhibits current leakage between the heaters. Thus, there is little or no current flow in the formation and the heaters may have long lengths as described above. Having the opposite polarity and substantially equal voltage potentials at the end portions of the heaters also halves the voltage applied at either end portion of the heater versus having one end portion of the heater grounded and one end portion at full potential. Reducing (halving) the voltage potential applied to an end portion of the

heater generally reduces current leakage, reduces insulator requirements, and/or reduces arcing distances because of the lower voltage potential to ground applied at the end portions of the heaters.

[0902] In certain embodiments, substantially vertical heaters are used to provide heat to the formation. Opposite polarity and substantially equal voltage potentials, as described above, may be applied to the end portions of the substantially vertical heaters. FIG. 98 depicts a side-view representation of substantially vertical heaters coupled to a substantially horizontal wellbore. Heaters 716A, 716B, 716C, 716D, 716E, 716F are located substantially vertical in hydrocarbon layer 460. First end portions of heaters 716A, 716B, 716C, 716D, 716E, 716F are coupled to bus bar 726A on a surface of the formation. Second end portions of heaters 716A, 716B, 716C, 716D, 716E, 716F are coupled to bus bar 726B in contacting section 642.

[0903] Bus bar 726B may be a bus bar located in a substantially horizontal wellbore in contacting section 642. Second end portions of heaters 716A, 716B, 716C, 716D, 716E, 716F may be coupled to bus bar 726B by any method described herein or any method known in the art. For example, containers with thermite powder are coupled to bus bar 726B (for example, by welding or brazing the containers to the bus bar), end portions of heaters 716A, 716B, 716C, 716D, 716E, 716F are placed inside the containers, and the thermite powder is activated to electrically couple the heaters to the bus bar. The containers may be coupled to bus bar 726B by, for example, placing the containers in holes or recesses in bus bar 726B or coupled to the outside of the bus bar and then brazing or welding the containers to the bus bar.

[0904] Bus bar 726A and bus bar 726B may be coupled to transformer 728 with cables 722, 724, as described above. Transformer 728 may provide voltages to bar 726A and bus bar 726B as described above for the embodiments depicted in FIGS. 95 and 96. For example, transformer 728 may apply a voltage potential to the first end portions of heaters 716A-F that is opposite in polarity and substantially equal in magnitude to a voltage potential applied to the second end portions of the heaters. Applying the same voltage potentials to the end portions of all heaters 716A-F may produce voltage potentials along the lengths of the heaters that are substantially the same along the lengths of the heaters. Applying the same voltage potentials to the end portions of all heaters 716A-F may inhibit current leakage between the heaters and/or into the formation. In some embodiments, heaters 716A-F are electrically coupled in pairs to the isolated delta winding on the secondary of a three-phase transformer.

[0905] In certain embodiments, it may be advantageous to allow some current leakage into the formation during early stages of heating to heat the formation at a faster rate. Current leakage from the heaters into the formation electrically heats the formation directly. The formation is heated by direct electrical heating in addition to conductive heat provided by the heaters. The

formation (the hydrocarbon layer) may have an initial electrical resistance that averages at least 10 ohm·m. In some embodiments, the formation has an initial electrical resistance of at least 100 ohm·m or of at least 300 ohm·m. Direct electrical heating is achieved by having opposite potentials applied to adjacent heaters in the hydrocarbon layer. Current may be allowed to leak into the formation until a selected temperature is reached in the heaters or in the formation. The selected temperature may be below or near the temperature that water proximate one or more heaters boils off. After water boils off, the hydrocarbon layer is substantially electrically isolated from the heaters and direct heating of the formation is inefficient. After the selected temperature is reached, the voltage potential is applied in the opposite polarity and substantially equal magnitude manner described above for FIGS. 95 and 96 so that adjacent heaters will have the same voltage potential along their lengths.

[0906] Current is allowed to leak into the formation by reversing the polarity of one or more heaters shown in FIG. 96 so that a first group of heaters has a positive voltage potential at first location 646 and a second group of heaters has a negative voltage potential at the first location. The first end portions, at first location 646, of a first group of heaters (for example, heaters 716A, 716B, 716D, 716E, 716G, 716H, 716J, 716K, depicted in FIG. 96) are applied with a positive voltage potential that is substantially equal in magnitude to a negative voltage potential applied to the second end portions, at second location 650, of the first group of heaters. The first end portions, at first location 646, of the second group of heaters (for example, heaters 716C, 716F, 716I, 716L) are applied with a negative voltage potential that is substantially equal in magnitude to the positive voltage potential applied to the first end portions of the first group of heaters. Similarly, the second end portions, at second location 650, of the second group of heaters are applied with a positive voltage potential substantially equal in magnitude to the negative potential applied to the second end portions of the first group of heaters. After the selected temperature is reached, the first end portions of both groups of heaters are applied with voltage potential that is opposite in polarity and substantially similar in magnitude to the voltage potential applied to the second end portions of both groups of heaters.

[0907] In some embodiments, heating elements 630 have a thin electrically insulating layer, described above, to inhibit current leakage from the heating elements. In some embodiments, the thin electrically insulating layer is aluminum oxide or thermal spray coated aluminum oxide. In some embodiments, the thin electrically insulating layer is an enamel coating of a ceramic composition. The thin electrically insulating layer may inhibit heating elements of a three-phase heater from leaking current between the elements, from leaking current into the formation, and from leaking current to other heaters in the formation. Thus, the three-phase heater may have a longer heater length.

[0908] In certain embodiments, a plurality of substantially horizontal (or inclined) heaters are coupled to a single substantially horizontal bus bar in the subsurface formation. Having the plurality of substantially horizontal heaters connected to a single bus bar in the subsurface reduces the overall footprint of heaters on the surface of the formation and the number of wells drilled in the formation. The number and spacing of heaters coupled to the single bus bar may be varied depending on factors such as, but not limited to, size of the treatment area, vertical thickness of the formation, heating requirements for the formation, and number of layers in the formation.

[0909] FIG. 99 depicts an embodiment of pluralities of substantially horizontal heaters 716A,B coupled to bus bars 726A,B in hydrocarbon layer 460. Heaters 716A,B have sections 718 in the overburden of hydrocarbon layer 460. Sections 718 may include high electrical conductivity, low thermal loss electrical conductors such as copper. Heaters 716A,B enter hydrocarbon layer 460 with substantially vertical sections and then redirect so that the heaters have substantially horizontal sections in the hydrocarbon layer 460. The substantially horizontal sections of 716A,B in hydrocarbon layer 460 may provide the majority of the heat to the hydrocarbon layer. Heaters 716A,B may be coupled to bus bars 726A,B, which are located distant from each other in the formation while being substantially parallel to each other.

[0910] In certain embodiments, heaters 716A,B include exposed metal heating elements. In certain embodiments, heaters 716A,B include exposed metal temperature limited heating elements. The heating elements may include ferromagnetic materials such as 9% by weight to 13% by weight chromium stainless steel like 410 stainless steel, chromium stainless steels such as T/P91 or T/P92, 409 stainless steel, VM12 (Vallourec and Mannesmann Tubes, France) or iron-cobalt alloys for use as temperature limited heaters. In some embodiments, the heating elements are composite temperature limited heating elements such as 410 stainless steel and copper composite heating elements or 347H, iron, copper composite heating elements. The substantially horizontal sections of heaters 716A,B in hydrocarbon layer 460 may have lengths of at least about 100 m, at least about 500 m, or at least about 1000 m, up to lengths of about 6000 m.

[0911] In some embodiments, as shown in FIG. 99, two groups of heaters 716A,B enter the subsurface near each other and then branch away from each other in hydrocarbon layer 460. Having the surface portions of more than one group of heaters located near each other creates less of a surface footprint of the heaters and allows a single group of surface facilities to be used for both groups of heaters.

[0912] In certain embodiments, the groups of heaters 716A or 716B are each coupled to a single transformer. In some embodiments, three heaters in the groups are coupled in a triad

configuration (each heater is coupled to one of the phases (A, B, or C) of a three phase transformer and the bus bar is coupled to the neutral, or center point, of the transformer). Each phase of the three-phase transformer may be coupled to more than one heater in each group of heaters (for example, phase A may be coupled to 5 heaters in the group of heaters 716A). In some embodiments, the heaters are coupled to a single phase transformer (either in series or in parallel configurations).

[0913] FIG. 100 depicts an alternative embodiment of pluralities of substantially horizontal heaters 716A,B coupled to bus bars 726A,B in hydrocarbon layer 460. In such an embodiment, two groups of heaters 716A,B enter the formation at distal locations on the surface of the formation. Heaters 716A,B branch towards each other in hydrocarbon layer 460 so that the ends of the heaters are directed towards each other. Heaters 716A,B may be coupled to bus bars 726A,B, which are located proximate each other and substantially parallel to each other. Bus bars 726A,B may enter the subsurface in proximity to each other so that the footprint of the bus bars on the surface is small.

[0914] In certain embodiments, heaters 716A,B, depicted in FIG. 100, are coupled to a single phase transformer in series or parallel. The heaters may be coupled so that the polarity (direction of current flow) alternates in the row of heaters so that each heater has an polarity opposite the heater adjacent to it. Additionally, heaters 716A,B and bus bars 726A,B may be electrically coupled such that the bus bars are opposite in polarity from each other (the current flows in opposite directions at any point in time in each bus bar). Coupling the heaters and the bus bars in such manners inhibits current leakage into and/or through the formation.

[0915] As shown in FIGS. 99 and 100, heaters 716A may be electrically coupled to bus bar 726A and heaters 716B may be electrically coupled to bus bar 726B. Bus bars 726A,B may electrically couple to the ends of heaters 716A,B and be a return or neutral connection for the heaters with bus bar 726A being the neutral connection for heaters 716A and bus bar 726B being the neutral connection for heaters 716B. Bus bars 726A,B may be located in wellbores that are formed substantially perpendicular to the path of wellbores with heaters 716A,B, as shown in FIG. 99. Directional drilling and/or magnetic steering may be used so that the wells for bus bars 726A,B and the wellbores for heaters 716A,B intersect.

[0916] In certain embodiments, heaters 716A,B are coupled to bus bars 726A,B using "mousetrap" type connectors 2028. In some embodiments, other couplings, such as those described herein or known in the art, are used to couple heaters 716A,B to bus bars 726A,B. For example, a molten metal or a liquid conducting fluid may fill up the connection space (in the wellbores) to electrically couple the heaters and the bus bars.

[0917] FIG. 101 depicts an enlarged view of an embodiment of bus bar 726 coupled to heater 716 with connectors 2028. In certain embodiments, bus bar 726 includes carbon steel or other electrically conducting metals. In some embodiments, a high electrical conductivity conductor or metal is coupled to or included in bus bar 726. For example, bus bar 726 may include carbon steel with copper cladded to the carbon steel.

[0918] In some embodiments, a centralizer or other centralizing device is used to locate or guide heaters 716 and/or bus bars 726 so that the heaters and bus bars can be coupled. FIG. 102 depicts an enlarged view of an embodiment of bus bar 726 coupled to heater 716 with connectors 2028 and centralizers 524. Centralizers 524 may locate heater 716 and/or bus bar 726 so that connectors 2028 easily couple the heater and the bus bar. Centralizers 524 may ensure proper spacing of heater 716 and/or bus bar 726 so that the heater and the bus bar can be coupled with connectors 2028. Centralizers 524 may inhibit heater 716 and/or bus bar 726 from contacting the sides of the wellbores at or near connectors 2028.

[0919] FIGS. 103 and 104 depict an embodiment of connector 2028 coupling to bus bar 726. FIG. 103 depicts a cross-section representation of connector 2028 coupling to bus bar 726. FIG. 104 depicts a three-dimensional representation of connector 2028 coupling to bus bar 726. Connector 2028 is shown in proximity to bus bar 726 (before the connector clamps around the bus bar). Connector 2028 is connected or directly attached to the heater so that the connector is rotatable around the end of the heater while maintaining electrical contact with the heater. Connector 2028 includes collets 2030. Collets 2030 are shaped (for example, diagonally cut or helically profiled) so that as the connector is pushed onto bus bar 726, the shape of the collets rotates the head of the connector as the collets slide over the bus bar. Collets 2030 may be spring loaded so that the collets hold down against bus bar 726 after the collets slide over the bus bar. Thus, connector 2028 clamps to bus bar 726 using collets 2030. Connector 2028, including collets 2030, is made of electrically conductive materials so that the connector electrically couples bus bar 726 to the heater attached to the connector.

[0920] In certain embodiments, a heater is electrically isolated from the formation because the heater has little or no voltage potential on the outside of the heater. FIG. 105 depicts an embodiment of a substantially u-shaped heater that electrically isolates itself from the formation. Heater 716 has a first end portion at a first opening on surface 534 and a second end portion at a second opening on the surface. In some embodiments, heater 716 has only the first end portion at the surface with the second end of the heater located in hydrocarbon layer 460 (the heater is a single-ended heater). FIGS. 106 and 107 depict embodiments of single-ended heaters that electrically isolate themselves from the formation. In certain embodiments, single-ended heater 716 has an elongated portion that is substantially horizontal in hydrocarbon layer 460, as shown

in FIGS. 106 and 107. In some embodiments, single-ended heater 716 has an elongated portion with an orientation other than substantially horizontal in hydrocarbon layer 460. For example, the single-ended heater may have an elongated portion that is oriented 15° off horizontal in the hydrocarbon layer.

[0921] As shown in FIGS. 105-107, heater 716 includes heating element 630 located in hydrocarbon layer 460. Heating element 630 may be a ferromagnetic conduit heating element or ferromagnetic tubular heating element. In certain embodiments, heating element 630 is a temperature limited heater tubular heating element. In certain embodiments, heating element 630 is a 9% by weight to 13% by weight chromium stainless steel tubular such as a 410 stainless steel tubular, a T/P91 stainless steel tubular, or a T/P92 stainless steel tubular. In certain embodiments, heating element 630 includes ferromagnetic material with a wall thickness of at least about one skin depth of the ferromagnetic material at 25 °C. In some embodiments, heating element 630 includes ferromagnetic material with a wall thickness of at least about two times the skin depth of the ferromagnetic material at 25 °C, at least about three times the skin depth of the ferromagnetic material at 25 °C, or at least about four times the skin depth of the ferromagnetic material at 25 °C.

[0922] Heating element 630 is coupled to one or more sections 718. Sections 718 are located in overburden 458. Sections 718 include higher electrical conductivity materials such as copper or aluminum. In certain embodiments, sections 718 are copper clad inside carbon steel.

[0923] Center conductor 730 is positioned inside heating element 630. In some embodiments, heating element 630 and center conductor 730 are placed or installed in the formation by unspooling the heating element and the center conductor from one or more spools while they are placed into the formation. In some embodiments, heating element 630 and center conductor 730 are coupled together on a single spool and unspooled as a single system with the center conductor inside the heating element. In some embodiments, heating element 630 and center conductor 730 are located on separate spools and the center conductor is positioned inside the heating element after the heating element is placed in the formation.

[0924] In certain embodiments, center conductor 730 is located at or near a center of heating element 630. Center conductor 730 may be substantially electrically isolated from heating element 630 along a length of the center conductor (for example, the length of the center conductor in hydrocarbon layer 460). In certain embodiments, center conductor 730 is separated from heating element 630 by one or more electrically-insulating centralizers. The centralizers may include silicon nitride or another electrically insulating material. The centralizers may inhibit electrical contact between center conductor 730 and heating element 630 so that, for example, arcing or shorting between the center conductor and the heating element is inhibited. In

some embodiments, center conductor 730 is a conductor (for example, a solid conductor or a tubular conductor) so that the heater is in a conductor-in-conduit configuration.

[0925] In certain embodiments, center conductor 730 is a copper rod or copper tubular. In some embodiments, center conductor 730 and/or heating element 630 has a thin electrically insulating layer to inhibit current leakage from the heating elements. In some embodiments, the thin electrically insulating layer is aluminum oxide or thermal spray coated aluminum oxide. In some embodiments, the thin electrically insulating layer is an enamel coating of a ceramic composition. The thin electrically insulating layer may inhibit heating elements of a three-phase heater from leaking current between the elements, from leaking current into the formation, and from leaking current to other heaters in the formation. Thus, the three-phase heater may have a longer heater length.

[0926] In certain embodiments, center conductor 730 is an insulated conductor. The insulated conductor may include an electrically conductive core inside an electrically conductive sheath with electrical insulation between the core and the sheath. In certain embodiments, the insulated conductor includes a copper core inside a non-ferromagnetic stainless steel (for example, 347 stainless steel) sheath with magnesium oxide insulation between the core and the sheath. The core may be used to conduct electrical current through the insulated conductor. In some embodiments, the insulated conductor is placed inside heating element 630 without centralizers or spacers between the insulated conductor and the heating element. The sheath and the electrical insulation of the insulated conductor may electrically insulate the core from heating element 630 if the center conductor and the heating element touch. Thus, the core and heating element 630 are inhibit from electrically shorting to each other. The insulated conductor or another solid center conductor 730 may be inhibited from being crushed or deformed by heating element 630.In certain embodiments, one end portion of center conductor 730 is electrically coupled to one end portion of heating element 630 at surface 534 using electrical coupling 732, as shown in FIG. 105. In some embodiments, the end of center conductor 730 is electrically coupled to the end of heating element 630 in hydrocarbon layer 460 using electrical coupling 732, as shown in FIGS. 106 and 107. Thus, center conductor 730 is electrically coupled to heating element 630 in a series configuration in the embodiments depicted in FIGS. 105-107. In certain embodiments, center conductor 730 is the insulated conductor and the core of the insulated conductor is electrically coupled to heating element 630 in the series configuration. Center conductor 730 is a return electrical conductor for heating element 630 so that current in the center conductor flows in an opposite direction from current in the heating element (as represented by arrows 734). The electromagnetic field generated by current flow in center conductor 730 substantially confines the flow of electrons and heat generation to the inside of

heating element 630 (for example, the inside wall of the heating element) below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic material in the heating element. Thus, the outside of heating element 630 is at substantially zero potential and the heating element is electrically isolated from the formation and any adjacent heater or heating element at temperatures below the Curie temperature and/or the phase transformation temperature range of the ferromagnetic material (for example, at 25 °C). Having the outside of heating element 630 at substantially zero potential and the heating element electrically isolated from the formation and any adjacent heater or heating element allows for long length heaters to be used in hydrocarbon layer 460 without significant electrical (current) losses to the hydrocarbon layer. For example, heaters with lengths of at least about 100 m, at least about 500 m, or at least about 1000 m may be used in hydrocarbon layer 460.

[0927] During application of electrical current to heating element 630 and center conductor 730, heat is generated by the heater. In certain embodiments, heating element 630 generates a majority or all of the heat output of the heater. For example, when electrical current flows through ferromagnetic material in heating element 630 and copper or another low resistivity material in center conductor 730, the heating element generates a majority or all of the heat output of the heater. Generating a majority of the heat in the outer conductor (heating element 630) instead of center conductor 730 may increase the efficiency of heat transfer to the formation by allowing direct heat transfer from the heat generating element (heating element 630) to the formation and may reduce heat losses across heater 716 (for example, heat losses between the center conductor and the outer conductor if the center conductor is the heat generating element). Generating heat in heating element 630 instead of center conductor 730 also increases the heat generating surface area of heater 716. Thus, for the same operating temperature of heater 716, more heat can be provided to the formation using the outer conductor (heating element 630) as the heat generating element rather than center conductor 730.

[0928] In some embodiments, a fluid flows through heater 716 (represented by arrows 736 in FIGS. 105 and 106) to preheat the formation and/or to recover heat from the heating element. In the embodiment depicted in FIG. 105, fluid flows from one end of heater 716 to the other end of the heater inside and through heating element 630 and outside center conductor 730, as shown by arrows 736. In the embodiment depicted in FIG. 106, fluid flows into heater 716 through center conductor 730, which is a tubular conductor, as shown by arrows 736. Center conductor 730 includes openings 738 at the end of the center conductor to allow fluid to exit the center conductor. Openings 738 may be perforations or other orifices that allow fluid to flow into and/or out of center conductor 730. Fluid then returns to the surface inside heating element 630 and outside center conductor 730, as shown by arrows 736.

[0929] Fluid flowing inside heater 716 (represented by arrows 736 in FIGS. 105 and 106) may be used to preheat the heater, to initially heat the formation, and/or to recover heat from the formation after heating is completed for the in situ heat treatment process. Fluids that may flow through the heater include, but are not limited to, air, water, steam, helium, carbon dioxide or other high heat capacity fluids. In some embodiments, a hot fluid, such as carbon dioxide, helium, or DOWTHERM® (The Dow Chemical Company, Midland, Michigan, U.S.A.), flows through the tubular heating elements to provide heat to the formation. The hot fluid may be used to provide heat to the formation before electrical heating is used to provide heat to the formation. In some embodiments, the hot fluid is used to provide heat in addition to electrical heating. Using the hot fluid to provide heat to or preheat the formation in addition to providing electrical heating may be less expensive than using electrical heating alone to provide heat to the formation. In some embodiments, water and/or steam flows through the tubular heating element to recover heat from the formation after in situ heat treatment of the formation. The heated water and/or steam may be used for solution mining and/or other processes.

[0930] In some embodiments, an insulated conductor heater is placed in the formation by itself and the outside of the insulated conductor heater is electrically isolated from the formation because the heater has little or no voltage potential on the outside of the heater. FIG. 108 depicts an embodiment of a single-ended, substantially horizontal insulated conductor heater that electrically isolates itself from the formation. In such an embodiment, heater 716 is insulated conductor 558. Insulated conductor 558 may be a mineral insulated conductor heater (for example, insulated conductor 558 depicted in FIGS. 109A and 109B). Insulated conductor 558 is located in opening 522 in hydrocarbon layer 460. In certain embodiments, opening 522 is an uncased or open wellbore. In some embodiments, opening 522 is a cased or lined wellbore. In some embodiments, insulated conductor heater 558 is a substantially u-shaped heater and is located in a substantially u-shaped opening (for example, the opening depicted in FIG. 105).

[0931] As shown in FIG. 108, insulated conductor 558 has little or no current flowing along the outside surface of the insulated conductor so that the insulated conductor is electrically isolated from the formation and leaks little or no current into the formation. The outside surface (or jacket) of insulated conductor 558 is a metal or thermal radiating body so that heat is radiated from the insulated conductor to the formation.

[0932] FIGS. 109A and 109B depict cross-sectional representations of an embodiment of insulated conductor 558 that is electrically isolated on the outside of jacket 506. In certain embodiments, jacket 506 is made of ferromagnetic materials. In one embodiment, jacket 506 is made of 410 stainless steel. In other embodiments, jacket 506 is made of T/P91 or T/P92 stainless steel. Core 508 is made of a highly conductive material such as copper. Electrical

insulator 500 is an electrically insulating material such as magnesium oxide. Insulated conductor 558 may be an inexpensive and easy to manufacture heater.

[0933] In the embodiment depicted in FIGS. 109A and 109B, core 508 brings current into the formation, as shown by the arrow. Core 508 and jacket 506 are electrically coupled at the distal end (bottom) of the heater. Current returns to the surface of the formation through jacket 506. The ferromagnetic properties of jacket 506 confine the current to the skin depth along the inside diameter of the jacket, as shown by arrows 736 in FIG. 109A. Jacket 506 has a thickness at least 2 or 3 times the skin depth of the ferromagnetic material used in the jacket so that most of the current is confined to the inside surface of the jacket and little or no current flows on the outside diameter of the jacket. Thus, there is little or no voltage potential on the outside of jacket 506. Having little or no voltage potential on the outside surface of insulated conductor 558 does not expose the formation to any high voltages, inhibits current leakage to the formation, and reduces or eliminates the need for isolation transformers, which decrease energy efficiency.

[0934] Because core 508 is made of a highly conductive material such as copper and jacket 506 is made of more resistive ferromagnetic material, a majority of the heat generated by insulated conductor 558 is generated in the jacket. Generating the majority of the heat in jacket 506 increases the efficiency of radiative heat transfer from insulated conductor 558 to the formation over an insulated conductor (or other heater) that uses a core or a center conductor to generate the majority of the heat.

[0935] In certain embodiments, core 508 is made of copper. Using copper in core 508 allows the heating section of the heater and the overburden section to have identical core materials. Thus, the heater may be made from one long core assembly. The long single core assembly reduces or eliminates the need for welding joints in the core, which can be unreliable and susceptible to failure. Additionally, the long, single core assembly heater may be manufactured remote from the installation site and transported in a final assembly (ready to install assembly) to the installation site. The single core assembly also allows for long heater lengths (for example, about 1000 m or longer) depending on the breakdown voltage of the electrical insulator.

[0936] In certain embodiments, jacket 506 is made from two or more layers of the same materials and/or different materials. Jacket 506 may be formed from two or more layers to achieve thicknesses needed for the jacket (for example, to have a thickness at least 3 times the skin depth of the ferromagnetic material used in the jacket). Manufacturing and/or material limitations may limit the thickness of a single layer of jacket material. For example, the amount each layer can be strained during manufacturing (forming) the layer on the heater may limit the thickness of each layer. Thus, to reach jacket thicknesses needed for certain embodiments of insulated conductor 558, jacket 506 may be formed from several layers of jacket material. For

example, three layers of T/P92 stainless steel may be used to form jacket 506 with a thickness of about 3 times the skin depth of the T/P92 stainless steel.

[0937] In some embodiments, jacket 506 includes two or more different materials. In some embodiments, jacket 506 includes different materials in different layers of the jacket. For example, jacket 506 may have one or more inner layers of ferromagnetic material chosen for their electrical and/or electromagnetic properties and one or more outer layers chosen for its non-corrosive properties.

[0938] In some embodiments, the thickness of jacket 506 and/or the material of the jacket are varied along the heater length. The thickness and/or material of jacket 506 may be varied to vary electrical properties and/or mechanical properties along the length of the heater. For example, the thickness and/or material of jacket 506 may be varied to vary the turndown ratio along the length of the heater. In some embodiments, the inner layer of jacket 506 includes copper or other highly conductive metals in the overburden section of the heater. The inner layer of copper limits heat losses in the overburden section of the heater.

[0939] FIGS. 110A and 110B depict an embodiment for using substantially u-shaped wellbores to time sequence heat two layers in a hydrocarbon containing formation. A single heater is shown in the embodiments depicted in FIGS. 110A and 110B, it is to be understood, however, that there are typically several heaters located in a hydrocarbon layer and that only one heater is shown in the drawings for simplicity. In FIG. 110A, opening 522A is formed in hydrocarbon layer 460A extending between openings 522. In certain embodiments, opening 522A is a substantially horizontal opening in hydrocarbon layer 460A. In some embodiments, opening 522A is an inclined opening in hydrocarbon layer 460A (for example, the layer may be an angled layer and the opening is angled to be substantially horizontal in the layer). Openings 522 are openings (for example, relatively vertical openings) that extend from the surface into hydrocarbon layer 460A. Hydrocarbon layer 460A may be separated from hydrocarbon layer 460B by impermeable zone 740. In certain embodiments, hydrocarbon layer 460B is an upper layer or a layer at a lesser depth than hydrocarbon layer 460A. In some embodiments, hydrocarbon layer 460B is a lower layer or a layer at a greater depth than hydrocarbon layer 460A. In certain embodiments, impermeable zone 740 provides a substantially impermeable seal that inhibits fluid flow between hydrocarbon layer 460A and hydrocarbon layer 460B. In certain embodiments (for example, in an oil shale formation), hydrocarbon layer 460A has a higher richness than hydrocarbon layer 460B.

[0940] As shown in FIG. 110A, heating element 630A is located in opening 522A in hydrocarbon layer 460A. Overburden casing 530 is placed along the relatively vertical walls of openings 522 in hydrocarbon layer 460B. Overburden casing 530 inhibits heat transfer to

hydrocarbon layer 460B while heat is provided to hydrocarbon layer 460A by heating element 630A. Heating element 630A is used to provide heat to hydrocarbon layer 460A. Formation fluids (such as mobilized hydrocarbons, pyrolyzed hydrocarbons, and/or water) may be produced from hydrocarbon layer 460A during and/or after heating of the layer by heating element 630A.

[0941] Heat may be provided to hydrocarbon layer 460A by heating element 630A for a selected amount of time (for example, a first amount of time). The selected amount of time may be based on a variety of factors including, but not limited to, formation characteristics or properties, present or future economic factors, or capital costs. For example, for an oil shale formation, hydrocarbon layer 460A may have a richness of about 0.12 L/kg (30.5 gals/ton) and the layer is heated for about 25 years. Production of formation fluids from hydrocarbon layer 460A may continue from the layer until production slows down to an uneconomical rate.

[0942] After hydrocarbon layer 460A is heated for the selected amount of time, heating element 630A is turned down and/or off. After heating element 630A is turned off, the heating element may be pulled firmly (for example, yanked) upwards so that the heating element breaks off at links 742. Both ends of heating element 630A at the surface may be pulled simultaneously so that links 742 break approximately simultaneously. Links 742 may be weak links designed to pull apart when a selected or sufficient amount of pulling force is applied to the links. For example, links 742 may be breakable mechanical couplings between portions of the heating element. The upper portions of heating element 630A are then pulled out of the formation and the substantially horizontal portion of heating element 630A is left in opening 522A, as shown in FIG. 110B.

[0943] In some embodiments, only one link 742 may be broken so that the upper portion above the one link can be removed and the remaining portions of the heater can be removed by pulling on the opposite end of the heater. Thus, the entire length of heating element 630A may be removed from the formation.

[0944] After upper portions of heating element 630A are removed from openings 522, plugs 744 may be placed into openings 522 at a selected location in hydrocarbon layer 460B, as depicted in FIG. 110B. In certain embodiments, plugs 744 are placed into openings 522 at or near impermeable zone 740. Plugs 744 may include isolation materials such as substantially impermeable materials or other materials that inhibit fluid flow between the hydrocarbon layers in the formation in openings 522 (for example, the plugs may isolate hydrocarbon layer 460A). In some embodiments, packing 532 is placed into openings 522 above plugs 744. In some embodiments, packing 532 is placed in openings 522 without plugs in the openings. Packing 532 may include substantially impermeable materials or other materials to inhibit fluid flow.

[0945] After plugs 744 and/or packing 532 is set into place in openings 522, substantially horizontal opening 522B may be formed in hydrocarbon layer 460B. Opening 522B may be formed by punching (for example, drilling) through casing 530 on the wall of opening 522. In certain embodiments, opening 522B is a substantially horizontal opening in hydrocarbon layer 460B. In some embodiments, opening 522B is an inclined opening in hydrocarbon layer 460B (for example, the layer may be an angled layer and the opening is angled to be substantially horizontal in the layer). Heating element 630B is then placed into opening 522B. Heating element 630B may be used to provide heat to hydrocarbon layer 460B. Formation fluids, such as pyrolyzed hydrocarbons and/or mobilized hydrocarbons, may be produced from hydrocarbon layer 460B during and/or after heating of the layer by heating element 630B.

[0946] In certain embodiments, opening 522 is a single-ended horizontal opening in hydrocarbon layer 460A (for example, the opening has only one end open at the surface of the formation). FIGS. 111A and 111B depict an embodiment for using single-ended horizontal wellbores to time sequence heat two layers in a hydrocarbon containing formation. A single heater is shown in the embodiments depicted in FIGS. 111A and 111B, it is to be understood, however, that there are typically several heaters located in a hydrocarbon layer and that only one heater is shown in the drawings for simplicity.

[0947] In FIG. 111A, opening 522A is formed in hydrocarbon layer 460A extending from opening 522. In certain embodiments, opening 522A is a substantially horizontal opening in hydrocarbon layer 460A that terminates in the layer. In some embodiments, opening 522A is an inclined opening in hydrocarbon layer 460A (for example, the layer may be an angled layer and the opening is angled to be substantially horizontal in the layer). Opening 522 is an opening (for example, a relatively vertical opening) that extends from the surface into hydrocarbon layer 460A. Hydrocarbon layer 460A may be separated from hydrocarbon layer 460B by impermeable zone 740. In certain embodiments, hydrocarbon layer 460B is an upper layer or a layer at a lesser depth than hydrocarbon layer 460A. In other embodiments, hydrocarbon layer 460B is a lower layer or a layer at a greater depth than hydrocarbon layer 460A. In certain embodiments, impermeable zone 740 provides a substantially impermeable seal that inhibits fluid flow between hydrocarbon layer 460A and hydrocarbon layer 460B. In certain embodiments (for example, in an oil shale formation), hydrocarbon layer 460A has a higher richness than hydrocarbon layer 460B.

[0948] As shown in FIG. 111A, heating element 630A is located in opening 522A in hydrocarbon layer 460A. Overburden casing 530 is placed along the relatively vertical walls of opening 522 in hydrocarbon layer 460B. Overburden casing 530 inhibits heat transfer to hydrocarbon layer 460B while heat is provided to hydrocarbon layer 460A by heating element

630A. Heating element 630A is used to provide heat to hydrocarbon layer 460A. Formation fluids (such as mobilized hydrocarbons, pyrolyzed hydrocarbons, and/or water) may be produced from hydrocarbon layer 460A during and/or after heating of the layer by heating element 630A.

[0949] Heat may be provided to hydrocarbon layer 460A by heating element 630A for a selected amount of time. The selected amount of time may be based on a variety of factors including, but not limited to, formation characteristics or properties, present or future economic factors, or capital costs. For example, for an oil shale formation, hydrocarbon layer 460A may have a richness of about 0.12 L/kg (30.5 gals/ton) and the layer is heated for about 25 years. Production of formation fluids from hydrocarbon layer 460A may continue from the layer until production slows down to an uneconomical rate.

[0950] After hydrocarbon layer 460A is heated for the selected amount of time, heating element 630A is turned down and/or off. After heating element 630A is turned down and/or off, the heating element may be removed from opening 522A. In some embodiments, one or more portions of heating element 630A are left in opening 522A. For example, portions of hydrocarbon layer 460A may clamp or squeeze on heating element 630A so that the heating element cannot be completely removed from opening 522A. In such cases, heating element 630A may be broken at link 742 and the upper portion of heating element 630A is pulled out of the formation and the substantially horizontal portion of the heating element is left in opening 522A.

[0951] After heating element 630A is removed from opening 522, plug 744 may be placed into opening 522 at a selected location in hydrocarbon layer 460B, as depicted in FIG. 111B. In certain embodiments, plug 744 is placed into opening 522 at or near impermeable zone 740. Plug 744 may include isolation materials such as substantially impermeable materials or other materials that inhibit fluid flow between the hydrocarbon layers in the formation in openings 522 (for example, the plug may isolate hydrocarbon layer 460A). In some embodiments, packing 532 is placed into opening 522 above plug 744. In some embodiments, packing 532 is placed in opening 522 without a plug in the opening. Packing 532 may include substantially impermeable materials or other materials to inhibit fluid flow.

[0952] After plug 744 and/or packing 532 is set into place in opening 522, substantially horizontal opening 522B may be formed in hydrocarbon layer 460B. Opening 522B may extend horizontally from opening 522. In certain embodiments, opening 522B is a substantially horizontal opening in hydrocarbon layer 460B that terminates in the layer. In some embodiments, opening 522B is an inclined opening in hydrocarbon layer 460B (for example, the layer may be an angled layer and the opening is angled to be substantially horizontal in the layer). Opening 522B may be formed by punching (for example, drilling) through casing 530 on

the wall of opening 522. Heating element 630B is then placed into opening 522B. Heating element 630B may be used to provide heat to hydrocarbon layer 460B. Formation fluids, such as pyrolyzed hydrocarbons and/or mobilized hydrocarbons, may be produced from hydrocarbon layer 460B during and/or after heating of the layer by heating element 630B.

[0953] Heating hydrocarbon layers 460A, 460B in the time-sequenced manners described above may be more economical than producing from only one layer or using vertical heaters to provide heat to the layers simultaneously. Using relatively vertical openings 522 to access both hydrocarbon layers at different times may save on capital costs associated with forming openings in the formation and providing surface facilities to power the heating elements. Heating hydrocarbon layer 460A first before heating hydrocarbon layer 460B may improve the economics of treating the formation (for example, the net present value of a project to treat the formation). In addition, impermeable zone 740 and packing 532 may provide a seal for hydrocarbon layer 460A after heating and production from the layer. This seal may be useful for abandonment of the hydrocarbon layer after treating the hydrocarbon layer.

[0954] In some embodiments, heat may be scavenged from hydrocarbon layer 460A and used to provide heat to hydrocarbon layer 460B. For example, a heat transfer fluid may be circulated through opening 522A to recover heat from hydrocarbon layer 460A. The heat transfer fluid may later be used to provide heat directly or indirectly (for example, using a heat exchanger to transfer heat to another heating fluid) to hydrocarbon layer 460B. In some embodiments, heat recovered from hydrocarbon layer 460A is used to provide power (for example, electrical power) to other heaters (for example, heating element 630B used in hydrocarbon layer 460B).

[0955] In some embodiments, synthesis gas generation or other post-treatment processes may be performed in hydrocarbon layer 460A before heating in hydrocarbon layer 460B is started. For example, carbon dioxide or other materials may be sequestered in hydrocarbon layer 460A before plugging or sealing off the layer.

[0956] In certain embodiments, portions of the wellbore that extend through the overburden include casings. The casings may include materials that inhibit inductive effects in the casings. Inhibiting inductive effects in the casings may inhibit induced currents in the casing and/or reduce heat losses to the overburden. In some embodiments, the overburden casings may include non-metallic materials such as fiberglass, polyvinylchloride (PVC), chlorinated PVC (CPVC), high-density polyethylene (HDPE), high temperature polymers (such as nitrogen based polymers), or other high temperature plastics. HDPEs with working temperatures in a usable range include HDPEs available from Dow Chemical Co., Inc. (Midland, Michigan, U.S.A.). The overburden casings may be made of materials that are spoolable so that the overburden casings can be spooled into the wellbore. In some embodiments, overburden casings may include non-

magnetic metals such as aluminum or non-magnetic alloys such as manganese steels having at least 10% manganese, iron aluminum alloys with at least 18% aluminum, or austentitic stainless steels such as 304 stainless steel or 316 stainless steel. In some embodiments, overburden casings may include carbon steel or other ferromagnetic material coupled on the inside diameter to a highly conductive non-ferromagnetic metal (for example, copper or aluminum) to inhibit inductive effects or skin effects. In some embodiments, overburden casings are made of inexpensive materials that may be left in the formation (sacrificial casings).

[0957] In certain embodiments, wellheads for the wellbores may be made of one or more non-ferromagnetic materials. FIG. 112 depicts an embodiment of wellhead 2032. The components in the wellheads may include fiberglass, PVC, CPVC, HDPE, high temperature polymers (such as nitrogen based polymers), and/or non-magnetic alloys or metals. Some materials (such as polymers) may be extruded into a mold or reaction injection molded (RIM) into the shape of the wellhead. Forming the wellhead from a mold may be a less expensive method of making the wellhead and save in capital costs for providing wellheads to a treatment site. Using non-ferromagnetic materials in the wellhead may inhibit undesired heating of components in the wellhead. Ferromagnetic materials used in the wellhead may be electrically and/or thermally insulated from other components of the wellhead. In some embodiments, an inert gas (for example, nitrogen or argon) is purged inside the wellhead and/or inside of casings to inhibit reflux of heated gases into the wellhead and/or the casings.

[0958] In some embodiments, ferromagnetic materials in the wellhead are electrically coupled to a non-ferromagnetic material (for example, copper) to inhibit skin effect heat generation in the ferromagnetic materials in the wellhead. The non-ferromagnetic material is in electrical contact with the ferromagnetic material so that current flows through the non-ferromagnetic material. In certain embodiments, as shown in FIG. 112, non-ferromagnetic material 2034 is coupled (and electrically coupled) to the inside walls of conduit 518 and wellhead walls 2036. In some embodiments, copper may be plasma sprayed, coated, clad, or lined on the inside and/or outside walls of the wellhead. In some embodiments, a non-ferromagnetic material such as copper is welded, brazed, clad, or otherwise electrically coupled to the inside and/or outside walls of the wellhead. For example, copper may be swaged out to line the inside walls in the wellhead. Copper may be liquid nitrogen cooled and then allowed to expand to contact and swage against the inside walls of the wellhead. In some embodiments, the copper is hydraulically expanded or explosively bonded to contact against the inside walls of the wellhead.

[0959] In some embodiments, two or more substantially horizontal wellbores are branched off of a first substantially vertical wellbore drilled downwards from a first location on a surface of the formation. The substantially horizontal wellbores may be substantially parallel through a

hydrocarbon layer. The substantially horizontal wellbores may reconnect at a second substantially vertical wellbore drilled downwards at a second location on the surface of the formation. Having multiple wellbores branching off of a single substantially vertical wellbore drilled downwards from the surface reduces the number of openings made at the surface of the formation.

[0960] Continuous tubulars, such as coil tubing, have been used for many years. Running continuous tubulars into and/or out of a wellbore may be simpler and faster than running tubing formed of conventional jointed pipe.

[0961] Continuous tubulars may be run into and/or out of wellbores using injectors. Injectors may force the continuous tubulars into the wells through a lubricator assembly or stuffing box to overcome any well pressure until the weight of the continuous tubulars exceeds the force applied by the well pressure that acts against the cross-sectional area of the continuous tubulars. Once the weight of the continuous tubular overcomes the pressure, the continuous tubular may need to be supported by the injector. The process may be reversed as the continuous tubular is removed from the well.

[0962] A method for running dual jointed tubing strings into and out of wells is described in U.S. Pat. No. 4,474,236 to Kellett. Kellett describes a method and apparatus for completing a well using jointed production and service strings of different diameters. The method includes steps of running the production string on a main tubing string hanger while maintaining control with a variable bore blowout preventer; and, running the service string into the main tubing string hanger while maintaining control with a dual bore blowout preventer.

[0963] Continuous tubulars have been used for various well treatment processes such as fracturing, acidizing, and gravel packing. Typically, several thousand feet of flexible, seamless tubing is coiled onto a large reel that is mounted on a truck or skid. A continuous tubular injector with a chain-track drive, or equivalent, may be mounted above the wellhead. The continuous tubular may be fed to the injector for injection into the well. The continuous tubular may be straightened as it is removed from the reel by a continuous tubular guide that aligns the continuous tubular with the wellbore and the injector mechanism.

[0964] The use of dual continuous tubulars for well servicing and production is known in the art. Recent developments in well completion and well workover have demonstrated the utility of using two continuous tubulars concurrently for many downhole operations. A difficulty with injecting dual continuous tubulars into a wellbore is the proximity of the respective continuous tubulars and the lack of working space to deploy a pair of continuous tubular injector assemblies mounted above the wellhead. This problem was apparently resolved with a coil tubing string

injector assembly adapted to simultaneously inject dual string coil tubing into a wellbore, as disclosed in U.S. Patent No. 6,516,891 to Dallas.

[0965] Another problem associated with the injection of dual continuous tubulars into a wellbore is the prevention of fluid leakage during the injection of the dual continuous tubulars, especially when a long downhole tool is connected to one or both of the continuous tubulars. Downhole tools typically have a larger diameter than the continuous tubular and cannot be plastically deformed, which presents certain difficulties. It is known in the art how to overcome these difficulties while injecting a single continuous tubular. For example, U.S. Patent No. 4,940,095 to Newman discloses a method of inserting a well service tool connected to a coiled tubing string, which avoids the high and/or remote mounting of a heavy coiled tubing injector drive mechanism. A closed-end lubricator is used to house the tool until it is run down through a blowout preventer connected to a top of the well. The pipe rams of the blowout preventer are closed around the tool to support it while a tubing injector is mounted to the wellhead and the coil tubing string is connected to the tool. The blowout preventer is then opened and the coil tubing string injector is used to run the tool into the well. However, Newman fails to address the use of dual string continuous tubulars.

[0966] Many subsurface wells are fitted with permanent sensors, such as pressure and temperature sensors, which require electrical power to transmit signals from the sensors to a remote point at the surface. Subsurface wells may employ subsurface equipment such as pumps or heaters, which may also require electrical power. In order to supply power to these subsurface pieces of equipment, electric current from a source outside of the wellhead must be transferred through the wellhead to the electrically responsive device. Electrical power can be supplied downhole by several methods. These methods include, but are not limited to, electrical umbilical cords, rigid tubular conductors, or coiled tubing. No matter which method of power supply is employed, in order to transfer the power through the wellhead, the power supply is transferred through either the tubing hanger or the casing hanger.

[0967] The extreme environmental conditions inside the wellhead coupled with the rough nature of completion operations may cause damage to devices used to supply electrical power. Damaged equipment may potentially lead to electrical short-circuits that can present a hazard to persons working around the wellhead. Since the majority of wellhead equipment is constructed of conductive materials, an electrical short inside of the wellhead may charge the outer surface of the wellhead. Unprotected persons may be exposed to electrical shock if contact is made with the wellhead's outer surface. Continuous tubulars subjected to electrical charge (for example, heaters) may be insulated from the wellhead of the wellbore.

[0968] Typically, a continuous tubular is inserted into a wellhead through a lubricator assembly or a stuffing box because there is a pressure differential between the wellbore and atmosphere. The pressure differential may be naturally or artificially created and produce oil or gas, or a mixture thereof, from the pressurized well. Wellhead mechanisms may inhibit movement of continuous tubulars upward and out of the wellbore as well as inhibit downward movement into the wellbore.

[0969] In certain embodiments, a suspension mechanism is capable of suspending dual continuous tubulars (for example, dual insulated conductor heaters). In some embodiments, the suspension mechanism includes slips or special fittings. With slips, a radial gripping force keeps dual continuous tubulars suspended and inhibits downward movement. In some embodiments, the slips inhibit upward movement (for example, upward movement of the dual continuous tubulars). Inhibiting upward movement may be accomplished by using a reverse slip arrangement. Conventional wellheads and hangers may not be designed to restrain movement of continuous tubulars in the upward direction. Instead, conventional wellheads and hangers may be only designed to suspend the strings due to the gravitational load of the continuous tubulars.

[0970] Deployment and suspension of continuous tubulars in the wellbore may require a mechanism that suspends the dual continuous tubulars in the wellhead by some suitable hanging mechanism or hanger. The hanging/suspension mechanisms may function when the dual legs of the continuous tubulars are deployed simultaneously. Conventionally, dual continuous tubulars are not deployed simultaneously. In some embodiments, a suspension mechanism is able to suspend the vertical downward load of both the tubulars as well as inhibit the upward movement of the tubulars.

[0971] FIG. 113 depicts an embodiment of a dual continuous tubular suspension mechanism 2040 for inhibiting movement of at least two continuous tubulars 484. Suspension mechanism 2040 may be formed or positioned within wellhead 450. Suspension mechanism 2040 may include threading cut along at least a portion of dual continuous tubulars 484 over expanded portion 484A of the tubular. In some embodiments, the tubular is a heater. In some embodiments, expanded portion 484A includes a threaded tubular portion to which a threaded collar is coupled. Suspension mechanism 2040 may include lower portion 2040A and upper portion 2040B. Upper portion 2040B may include at least two openings with diameters large enough to allow passage of the tubulars as well as threaded collar 2042, but small enough to inhibit passage of expanded portions of the tubulars. Lower portion 2040A may include lip 2040A'. Lip 2040A' may inhibit movement of the threaded collars in a downward direction. Lip 2040A'restricts movement of the tubulars in a downward direction once the expanded portion of the tubulars are threaded into the collars.

[0972] The wellhead and the suspension mechanism may include one or more seals 2038. Seals 2038 may inhibit wellbore fluids from migrating upwards. Seals 2038 may help maintain a desired pressure in the wellbore. Wellcap 448 keeps the suspension mechanism in place and inhibits upward movement. Wellhead 450 may include an opening in which the suspension mechanism is positioned. The opening may narrow to a diameter less than that of the suspension mechanism to inhibit downward movement of the suspension mechanism.

[0973] FIG. 114 depicts an embodiment of dual continuous tubular suspension mechanism 2040 for inhibiting movement of at least two continuous tubulars 484. Suspension mechanism 2040 may be formed or positioned within wellhead 450. Continuous tubulars 484 may include expanded portion 484A and function in a similar fashion as is described in the embodiment depicted in FIG. 113. Expanded portion 484A depicted in FIG. 114, however, may be formed by welding or otherwise attaching two pieces of split cylinder to tubular 484.

[0974] FIGS. 115A-B depict embodiments of dual continuous tubular suspension mechanisms 2040. Suspension mechanisms 2040 include slip mechanisms that inhibit upward and downward movement of tubulars 484. The slip mechanisms may include inhibitors 2044. Inhibitors 2044 may allow movement in a first direction while inhibiting movement in a second direction. The second direction may be in a direction opposite to the first direction. Inhibitors 2044 may include upper inhibitors 2044B and lower inhibitors 2044A. Upper inhibitors 2044B may allow movement of the tubulars in a downward direction while inhibiting movement of the tubulars in an upward direction. Lower inhibitors 2044A may allow movement of the tubulars in an upward direction, while inhibiting movement of the tubulars in a downward direction. Inhibitors 2044 may inhibit movement using serrations angled such that the serrations engage a tubular when the tubular moves in a first direction, but not when the tubular moves in a second direction that is substantially opposite to the first direction.

[0975] In some embodiments, inhibitors include coatings. The coating may impart specific desirable properties to the inhibitor to which the coating is applied. For example, a coating may include a temperature resistant polymer coating.

[0976] Suspension mechanism 2040 may include lower portion 2040A and upper portion 2040B. Upper portion 2040B may include at least two openings with diameters large enough to allow passage of the tubulars at both ends of each opening, but small enough at the proximal ends of the openings to inhibit passage of upper inhibitors 2044B in an upward direction. The distal ends of the openings may be large enough to allow the upper inhibitors to sit within the openings of the upper portion 2044B of suspension mechanism 2040. Lower portion 2040A may include at least two openings with diameters large enough to allow passage of the tubulars at both ends of the openings, but small enough at the distal end of each opening to inhibit passage of lower

inhibitors 2044A in a downward direction. The proximal ends of the openings may be large enough to allow the lower inhibitors to sit within the openings of lower portion 2040A of suspension mechanism 2040.

[0977] Suspension mechanism 2040 may include locks 2046. In some embodiments, locks 2046 are screws, bolts, or other types of fasteners. Locks 2046 inhibit movement of one or more portions of suspension mechanism 2040 within wellhead 450. Wellhead 450 may include an opening in which suspension mechanism 2040 is positioned. The opening may narrow to a diameter less than that of suspension mechanism 2040 to inhibit downward movement of the suspension mechanism.

[0978] FIGS. 116-117 depict embodiments of dual continuous tubular suspension mechanisms 2040 within wellhead 450. As detailed in FIGS. 115A-B, suspension mechanisms 2040 employs a slip mechanism using upper and lower inhibitors 2044. In FIG. 116, wellcap 448 of wellhead 450 assists in keeping suspension mechanism 2040 in position. Lock 2046 inhibits upward movement of the wellcap and suspension mechanism 2040. In the embodiment depicted in FIG. 116, wellcap 448 is a part of a seal assembly using seals 2038.

[0979] FIG. 117 depicts an embodiment of suspension mechanisms 2040 in wellhead 450. Wellcap 448 may be sandwiched between upper portion 2040A and lower portion 2040B of suspension mechanism 2040. Lock 2046 inhibits upward movement of upper portion 2040A of the suspension mechanism, and the wellcap and suspension mechanism as a whole. Locks 2046' inhibit movement of upper portion 2040A and lower portion 2040B of suspension mechanism 2040 and wellcap 448 in relation to one another.

[0980] FIG. 118 depicts an embodiment of pass-through fitting 2048 used to suspend tubulars 484. Pass-through fitting 2048 may function to suspend tubulars 484. Pass-through fitting 2048 may include commercially available products (for example, available from Swagelok Company (Solon, Ohio, USA) or VULKAN LOKRING Rohrverbindung GmbH & Co.KG (Herne, Germany)). Pass-through fitting 2048 may inhibit movement of tubulars 484 in the downward direction. A second mechanism may be utilized to inhibit movement of the tubulars in the upward direction. The second mechanism may be a reverse configuration of the pass-through fittings 2048.

[0981] FIG. 119 depicts an embodiment of dual slip suspension mechanism 2040 for inhibiting movement of tubulars 484 positioned in an opening of wellhead 450. FIG. 119 depicts a two-way lock arrangement using a slip mechanism. Bottom threading has right-handed threading, and top threading has left-handed threading. Rotation of the center nut in the clockwise direction (when viewed from top) causes the fittings to be drawn together, tightening the slips and causing the slips to grip the tubular/rod/heater. The entire assembly can then be suspended in a wellhead

housing as shown. Using the two lock-screws shown in the figure, the entire assembly can be locked into place. The two lock-screws may suspend the tubular/rod/heater and restrict downward and upward movement of the tubular/rod/heater.

[0982] FIGS. 120A-B depict embodiments of lower portion of split suspension mechanisms 2040A and lower split inhibitor assemblies 2044A for hanging dual continuous tubulars 484. Lower inhibitor assemblies 2044A and lower portion of suspension mechanisms 2040A may be split such that they fit together around tubulars 484. When the assembly is positioned in a wellhead the assembly may function as a compression fitting to inhibit downward movement of the tubulars. Lower inhibitor assemblies 2044A may include special non-marking dies or surfaces (for example, WC particles (tungsten carbide particles) embedded in mild steel) that function to simultaneously hold both the tubulars. Lower inhibitor assemblies 2044A may include a specific taper angle that sits in lower portion of suspension mechanisms 2040A. In this configuration, the lower inhibitor assemblies 2044A are shown to have special grit-faced non-marking surface.

[0983] FIG. 121 depicts an embodiment of dual slip suspension mechanisms 2040 for inhibiting movement of tubulars 484 with a reverse configuration relative to the embodiment depicted in FIG. 117. Upper inhibitor 2044B, which prevents upward movement, is deployed first and locked into place with bottom locks 2046' and lower portion of suspension mechanism 2040A. Lower inhibitor 2044A, which hangs the weight of the pipe and inhibits downward movement of pipe, is deployed in reverse order and locked in place with bottom locks 2046'' and upper portion of suspension mechanism 2040B. Wellcap 448 including seals 2038 are introduced next from the top. The suspension mechanism 2040 may be locked in position using locks 2046'''. A third or middle portion 2040C of the suspension mechanism cradles both the upper and lower inhibitors while the upper portion 2044B and lower portion 2044A of the suspension mechanism inhibit movement of the inhibitors within openings in middle portion 2040C of the suspension mechanism.

[0984] FIG. 122 depicts an embodiment of a two-part dual slip mechanism of suspension mechanism 2040 for inhibiting movement of tubulars 484. Middle portion 2040C of the suspension mechanism is divided into two portions, lower portion 2040C' and upper portion 2040C''. The two portions of middle portion 2040C may be coupled together using lock 2046C. Lock 2046C may include threaded studs as depicted in FIG. 122. The top half of each stud 2046C may have left-handed threading and the bottom half of each stud may have right-handed threading. Each stud 2046C screws into the bottom and top of upper portion 2040C'' and lower portion 2040C' of suspension mechanism 2040. When the stud is rotated in the clockwise direction when viewed from the top, both upper portion 2040C'' and lower portion 2040C'

approach each other. Each stud is rotated a little each time in sequence going around such that the upper portion 2040C'' and lower portion 2040C' move towards each other gradually and substantially uniformly. The movement causes the inhibitors to tighten and grip the tubulars.

[0985] In some embodiments, the above operation is done in a 'false wellhead housing' (not shown) just above the wellhead after the inhibitors are tightened together, the tubulars are lifted, until they clear the false-wellhead, which is then removed. The tubulars along with the suspension mechanism are lowered into a wellhead housing and the load is transferred to the shoulder (for example, a protrusion or narrowing of the opening in the wellhead which inhibits movement of the suspension mechanism beyond the protrusion). The locks 2046''' are tightened to inhibit movement of the suspension mechanism relative to the wellhead.

[0986] FIG. 123 depicts an embodiment of two-part dual slip suspension mechanism 2040 for inhibiting movement of tubulars 484 with separate locks 2046. FIG. 123 depicts an embodiment with a reverse configuration of inhibitors 2044 from the configuration depicted in FIGS. 121-122. In FIG. 123, the suspension mechanism is depicted in two distinct sections. The two sections may be activated separately. Lower portion 2040A of a suspension mechanism may include lower portion 2040A' and upper portion 2040A''. Portions 2040A' and 2040A'' function in combination when activated to inhibit movement of inhibitors 2044B and hence inhibit upward movement of tubulars 484. Lower portion 2040A may be activated by assembling portions 2040A', 2040A'' and inhibitors 2044B, inserting the assembly until downward movement is inhibited by lip 2050', and upon positioning tubulars 484, activating lock 2046'. Activating lock 2046' may compress lower portion assembly together such that inhibitors 2044B grip tubulars 484. Upper portion 2040B may be activated by assembling portion 2040B and inhibitors 2044A, inserting the assembly until downward movement is inhibited by lip 2050'', and activating lock 2046''after positioning tubulars 484. Activating lock 2046'' may compress upper portion 2040B against lip 2050''. Inhibitors 2044A may be held in position within opening in upper portion 2040B by gravity.

[0987] FIG. 124 depicts an embodiment of dual slip suspension mechanism 2040 with locking upper plate 2040B for inhibiting movement of tubulars 484. The embodiment of lower portion 2040A depicted in FIG. 124 may function in a similar manner to upper portion 2040B of the suspension mechanism depicted in FIG. 123. Inhibitors 2044A inhibit downward movement of tubulars 484. However, instead of including a second set of inhibitors to inhibit upward movement as in FIG. 123, upper portion 2040B (for example, a plate) is positioned above lower portion 2040A. Upper portion 2040B locks inhibitors 2044A in place to inhibit upward movement of tubulars 484 upon activation of locks. Activating locks 2046'' couples upper portion 2040B to lower portion 2040A.

[0988] In some embodiments, lower portion 2040A may include a tapered opening extending through it. The lower portion may include a carrier with a tapered shape complementary to the tapered opening in the lower portion. The carrier may sit within the tapered opening of the lower portion. Inhibitors 2044A fit in complementary tapered openings through the carrier. The load of the tubulars, once positioned, is transferred from the inhibitors to the carrier to the lower portion, and then to the wellhead. Using a lower portion with a carrier for the inhibitors may be advantageous when the distance between tubulars is small.

[0989] FIG. 125 depicts an embodiment of segmented dual slip suspension mechanism 2040 with locking screws 2046 for inhibiting movement of tubulars 484. FIG. 125 depicts an arrangement where inhibitors 2044 are shown in six separate segments that are individually controlled by six locks 2046. The profile on inhibitors 2044 are such that when all the inhibitor segments are in-place, the inhibitor segments conform exactly to the contours of the dual tubulars and grip them tight to prevent motion in both the upward and downward directions. The weight of the tubulars is transferred by the inhibitors to a load shoulder (for example, lip 2050) in the wellhead.

[0990] Power supplies are used to provide power to downhole power devices (downhole loads) such as, but not limited to, reservoir heaters, electric submersible pumps (ESPs), compressors, electric drills, electrical tools for construction and maintenance, diagnostic systems, sensors, or acoustic wave generators. Surface based power supplies may have long supply cabling (power cables) that contribute to problems such as voltage drops and electrical losses. Thus, it may be necessary to provide power to the downhole loads at high voltages to reduce electrical losses. However, many downhole loads are limited by an acceptable supply voltage level to the load. Therefore, an efficient high-voltage energy supply may not be viable without further conditioning. In such cases, a system for stepping down the voltage from the high voltage supply cable to the low voltage load may be necessary. The system may be a transformer.

[0991] The electrical power supply for downhole loads is typically provided using alternating voltage (AC voltage) from supply grids of 50 Hz or 60 Hz frequency. The voltage of the supply grid may correspond to the voltage of the downhole load. High supply voltages may reduce loss and voltage drop in the supply cable and/or allow the use of supply cables with relatively small cross sections. High supply voltages, however, may cause technically difficulties and require cost intensive isolation efforts at the load. Voltage drops, electrical losses, and supply cable cross section limits may limit the length of the supply cable and, thus, the wellbore depth or depth of the downhole load. Locating the transformer downhole may reduce the amount of cabling needed to provide power to the downhole loads and allow deeper wellbore depths and/or downhole load depths while minimizing voltage drops and electrical losses in the power system.

[0992] Current technical solutions for offshore-applications make use of sea-bed mounted step-down transformers to reduce cable loss (for example, "Converter-Fed Subsea Motor Drives", Raad, R.O.; Henriksen, T.; Raphael, H.B.; Hadler-Jacobsen, A.; Industry Applications, IEEE Transactions on Volume 32, Issue 5, Sept.-Oct. 1996 Page(s): 1069-1079). However, these sea-bed mounted transformers may not be useful to drive downhole loads under solid ground (for example, in a subsurface wellbore).

[0993] FIGS. 126 and 127 depict an embodiment of transformer 728 that may be located in a subsurface wellbore. FIG. 126 depicts a top view representation of the embodiment of transformer 728 showing the windings and core of the transformer. FIG. 127 depicts a side view representation of the embodiment of transformer 728 showing the windings, the core, and the power leads. Transformer 728 includes primary windings 2052A and secondary windings 2052B. Primary windings 2052A and secondary windings 2052B may have different cross-sectional areas.

[0994] Core 2054 may include two half-shell core sections 2054A and 2054B around primary windings 2052A and secondary windings 2052B. In certain embodiments, core sections 2054A and 2054B are semicircular, symmetric shells. Core sections 2054A and 2054B may be single pieces that extend the full length of transformer 728 or the core sections may be assembled from multiple shell segments put together (for example, multiple pieces strung together to make the core sections). In certain embodiments, a core section is formed by putting together the section from two halves. The two halves of the core section may be put together after the windings, which may be pre-fabricated, are placed in the transformer.

[0995] In certain embodiments, core sections 2054A and 2054B have about the same cross section on the circumference of transformer 728 so that the core properly guides the magnetic flux in the transformer. Core sections 2054A and 2054B may be made of several layers of core material. Certain orientations of these layers may be designed to minimize eddy current losses in transformer 728. In some embodiments, core sections 2054A and 2054B are made of continuous ribbons and windings 2052A and 2052B are wound into the core sections.

[0996] Transformer 728 may have certain advantages over current transformer configurations (such as a toroid core design with the winding on the outside of the cores). Core sections 2054A and 2054B have outer surfaces that offer large surface areas for cooling transformer 728. Additionally, transformer 728 may be sealed so that a cooling liquid may be continuously run across the outer surfaces of the transformer to cool the transformer. Transformer 728 may be sealed so that cooling liquids do not directly contact the inside of the core and/or the windings. In certain embodiments, transformer is sealed in an epoxy resin or other electrically insulating sealing material. Cooling transformer 728 allows the transformer to operate at higher power

densities. In certain embodiments, windings 2052A and 2052B are substantially isolated from core sections 2054A and 2054B so that the outside surfaces of transformer 728 may touch the walls of a wellbore without causing electrical problems in the wellbore.

[0997] In some embodiments, the profile of the core of transformer 728 and/or the winding window profile are made with clearances to allow for additional cooling devices, mechanical supports, and/or electrical contacts on the transformer. In some embodiments, transformer 728 is coupled to one or more additional transformers in the subsurface wellbore to increase power in the wellbore and/or phase options in the wellbore. Transformer 728 and/or the phases of the transformer may be coupled to the additional transformers, and/or the varying phases of the additional transformers, in either series or parallel configurations as needed to provide power to the downhole load.

[0998] FIG. 128 depicts an embodiment of transformer 728 in wellbore 756. Transformer 728 is located in the overburden section of wellbore 756. The overburden section of wellbore 756 has overburden casing 530 on the walls of the wellbore. Overburden casing 530 electrically and thermally insulates the overburden from the inside of wellbore 756. Packing material 532 is located at the bottom of the overburden section of wellbore 756. Packing material 532 inhibits fluid flow between the overburden section of wellbore 756 and the heating section of the wellbore.

[0999] Power lead 2058 may be coupled to transformer 728 and pass through packing material 532 to provide power to the downhole load (for example, a downhole heater). In certain embodiments, cooling fluid 2056 is located in wellbore 756. Transformer 728 may be immersed in cooling fluid 2056. Cooling fluid 2056 may cool transformer 728 by removing heat from the transformer and moving the heat away from the transformer. Cooling fluid 2056 may be circulated in wellbore 756 to increase heat transfer between transformer 728 and the cooling fluid. In some embodiments, cooling fluid 2056 is circulated to a chiller or other heat exchanger to remove heat from the cooling fluid and maintain a temperature of the cooling fluid at a selected temperature. Maintaining cooling fluid 2056 at a selected temperature may provide efficient heat transfer between the cooling fluid and transformer 728 so that the transformer is maintained at a desired operating temperature.

[1000] In certain embodiments, cooling fluid 2056 maintains a temperature of transformer 728 below a selected temperature. The selected temperature may be a maximum operating temperature of the transformer. In some embodiments, the selected temperature is a maximum temperature that allows for a selected operational efficiency of the transformer. In some embodiments, transformer 728 operates at an efficiency of at least 95%, at least 90%, at least 80%, or at least 70% when the transformer operates below the selected temperature.

[1001] In certain embodiments, cooling fluid 2056 is water. In some embodiments, cooling fluid 2056 is another heat transfer fluid such as, but not limited to, oil, ammonia, helium, or Freon® (E. I. du Pont de Nemours and Company, Wilmington, Delaware, U.S.A.). In some embodiments, the wellbore adjacent to the overburden functions as a heat pipe. Transformer 728 boils cooling fluid 2056. Vaporized cooling fluid 2056 rises in the wellbore, condenses, and flows back to transformer 728. Vaporization of cooling fluid 2056 transfers heat to the cooling fluid and condensation of the cooling fluid allows heat to transfer to the overburden. Transformer 728 may operate near the vaporization temperature of cooling fluid 2056.

[1002] In some embodiments, cooling fluid is circulated in a pipe that surrounds the transformer. The pipe may be in direct thermal contact with the transformer so that heat is removed from the transformer into the cooling fluid circulating through the pipe. In some embodiments, the transformer includes fans, heat sinks, fins, or other devices that assist in transferring heat away from the transformer. In some embodiments, the transformer is, or includes, a solid state transformer device such as an AC to DC converter.

[1003] In certain embodiments, cooling fluid 2056 is circulated using a heat pipe in wellbore 756. FIG. 129 depicts an embodiment of transformer 728 in wellbore 756 with heat pipes 2060A,B. Lid 2062 is placed at the top of a reservoir of cooling fluid 2056 that surrounds transformer 728. Heated cooling fluid expands and flows up heat pipe 2060A. The heated cooling fluid 2056 cools adjacent to the overburden and flows back to lid 2062. The cooled cooling fluid 2056 flows back into the reservoir through heat pipe 2060B. Heat pipes 2060A,B act to create a flow path for the cooling fluid so that the cooling fluid circulates around transformer 728 and maintains a temperature of the transformer below the selected temperature.

[1004] Computational analysis has shown that a circulated water column was sufficient to cool a 60 Hz transformer that was 125 feet in length and generated 80 W/ft of heat. The transformer and the formation were initially at ambient temperatures. The water column was initially at an elevated temperature. The water column and transformer cooled over a period of about 1 to 2 hours. The transformer initially heated up (but was still at operable temperatures) but then was cooled by the water column to lower operable temperatures. The computations also showed that the transformer would be cooled by the water column when the transformer and the formation were initially at higher than normal temperatures.

[1005] In certain embodiments, a temperature limited heater is utilized for heavy oil applications (for example, treatment of relatively permeable formations or tar sands formations). A temperature limited heater may provide a relatively low Curie temperature and/or phase transformation temperature range so that a maximum average operating temperature of the heater is less than 350 °C, 300 °C, 250 °C, 225 °C, 200 °C, or 150 °C. In an embodiment (for example,

for a tar sands formation), a maximum temperature of the heater is less than about 250 °C to inhibit olefin generation and production of other cracked products. In some embodiments, a maximum temperature of the heater above about 250 °C is used to produce lighter hydrocarbon products. For example, the maximum temperature of the heater may be at or less than about 500 °C.

[1006] A heater may heat a volume of formation adjacent to a production wellbore (a near production wellbore region) so that the temperature of fluid in the production wellbore and in the volume adjacent to the production wellbore is less than the temperature that causes degradation of the fluid. The heat source may be located in the production wellbore or near the production wellbore. In some embodiments, the heat source is a temperature limited heater. In some embodiments, two or more heat sources may supply heat to the volume. Heat from the heat source may reduce the viscosity of crude oil in or near the production wellbore. In some embodiments, heat from the heat source mobilizes fluids in or near the production wellbore and/or enhances the radial flow of fluids to the production wellbore. In some embodiments, reducing the viscosity of crude oil allows or enhances gas lifting of heavy oil (approximately at most 10° API gravity oil) or intermediate gravity oil (approximately 12° to 20° API gravity oil) from the production wellbore. In certain embodiments, the initial API gravity of oil in the formation is at most 10°, at most 20°, at most 25°, or at most 30°. In certain embodiments, the viscosity of oil in the formation is at least 0.05 Pa·s (50 cp). In some embodiments, the viscosity of oil in the formation is at least 0.10 Pa·s (100 cp), at least 0.15 Pa·s (150 cp), or at least at least 0.20 Pa·s (200 cp). Large amounts of natural gas may have to be utilized to provide gas lift of oil with viscosities above 0.05 Pa·s. Reducing the viscosity of oil at or near the production wellbore in the formation to a viscosity of 0.05 Pa·s (50 cp), 0.03 Pa·s (30 cp), 0.02 Pa·s (20 cp), 0.01 Pa·s (10 cp), or less (down to 0.001 Pa·s (1 cp) or lower) lowers the amount of natural gas needed to lift oil from the formation. In some embodiments, reduced viscosity oil is produced by other methods such as pumping.

[1007] The rate of production of oil from the formation may be increased by raising the temperature at or near a production wellbore to reduce the viscosity of the oil in the formation in and adjacent to the production wellbore. In certain embodiments, the rate of production of oil from the formation is increased by 2 times, 3 times, 4 times, or greater up to 20 times over standard cold production, which has no external heating of formation during production. Certain formations may be more economically viable for enhanced oil production using the heating of the near production wellbore region. Formations that have a cold production rate approximately between 0.05 m3/(day per meter of wellbore length) and 0.20 m3/(day per meter of wellbore length) may have significant improvements in production rate using heating to reduce the

viscosity in the near production wellbore region. In some formations, production wells up to 775 m, up to 1000 m, or up to 1500 m in length are used. For example, production wells between 450 m and 775 m in length are used, between 550 m and 800 m are used, or between 650 m and 900 m are used. Thus, a significant increase in production is achievable in some formations. Heating the near production wellbore region may be used in formations where the cold production rate is not between 0.05 m3/(day per meter of wellbore length) and 0.20 m3/(day per meter of wellbore length), but heating such formations may not be as economically favorable. Higher cold production rates may not be significantly increased by heating the near wellbore region, while lower production rates may not be increased to an economically useful value.

[1008] Using the temperature limited heater to reduce the viscosity of oil at or near the production well inhibits problems associated with non-temperature limited heaters and heating the oil in the formation due to hot spots. One possible problem is that non-temperature limited heaters can causing coking of oil at or near the production well if the heater overheats the oil because the heaters are at too high a temperature. Higher temperatures in the production well may also cause brine to boil in the well, which may lead to scale formation in the well. Non-temperature limited heaters that reach higher temperatures may also cause damage to other wellbore components (for example, screens used for sand control, pumps, or valves). Hot spots may be caused by portions of the formation expanding against or collapsing on the heater. In some embodiments, the heater (either the temperature limited heater or another type of non-temperature limited heater) has sections that are lower because of sagging over long heater distances. These lower sections may sit in heavy oil or bitumen that collects in lower portions of the wellbore. At these lower sections, the heater may develop hot spots due to coking of the heavy oil or bitumen. A standard non-temperature limited heater may overheat at these hot spots, thus producing a non-uniform amount of heat along the length of the heater. Using the temperature limited heater may inhibit overheating of the heater at hot spots or lower sections and provide more uniform heating along the length of the wellbore.

[1009] In some embodiments, oil or bitumen cokes in a perforated liner or screen in a heater/production wellbore (for example, coke may form between the heater and the liner or between the liner and the formation). Oil or bitumen may also coke in a toe section of a heel and toe heater/production wellbore, as shown in and described below for FIG. 145. A temperature limited heater may limit a temperature of a heater/production wellbore below a coking temperature to inhibit coking in the well so that the wellbore does not plug up.

[1010] In certain embodiments, fluids in the relatively permeable formation containing heavy hydrocarbons are produced with little or no pyrolyzation of hydrocarbons in the formation. In certain embodiments, the relatively permeable formation containing heavy hydrocarbons is a tar

sands formation. For example, the formation may be a tar sands formation such as the Athabasca tar sands formation in Alberta, Canada or a carbonate formation such as the Grosmont carbonate formation in Alberta, Canada. The fluids produced from the formation are mobilized fluids. Producing mobilized fluids may be more economical than producing pyrolyzed fluids from the tar sands formation. Producing mobilized fluids may also increase the total amount of hydrocarbons produced from the tar sands formation.

[1011] FIGS. 130-133 depict side view representations of embodiments for producing mobilized fluids from tar sands formations. In FIGS. 130-133, heaters 716 have substantially horizontal heating sections in hydrocarbon layer 460 (as shown, the heaters have heating sections that go into and out of the page). FIG. 130 depicts a side view representation of an embodiment for producing mobilized fluids from a tar sands formation with a relatively thin hydrocarbon layer. FIG. 131 depicts a side view representation of an embodiment for producing mobilized fluids from a hydrocarbon layer that is thicker than the hydrocarbon layer depicted in FIG. 130. FIG. 132 depicts a side view representation of an embodiment for producing mobilized fluids from a hydrocarbon layer that is thicker than the hydrocarbon layer depicted in FIG. 131. FIG. 133 depicts a side view representation of an embodiment for producing mobilized fluids from a tar sands formation with a hydrocarbon layer that has a shale break.

[1012] In FIG. 130, heaters 716 are placed in an alternating triangular pattern in hydrocarbon layer 460. In FIGS. 131, 132, and 133, heaters 716 are placed in an alternating triangular pattern in hydrocarbon layer 460 that repeats vertically to encompass a majority or all of the hydrocarbon layer. In FIG. 133, the alternating triangular pattern of heaters 716 in hydrocarbon layer 460 repeats uninterrupted across shale break 746. In FIGS. 130-133, heaters 716 may be equidistantly spaced from each other. In the embodiments depicted in FIGS. 130-133, the number of vertical rows of heaters 716 depends on factors such as, but not limited to, the desired spacing between the heaters, the thickness of hydrocarbon layer 460, and/or the number and location of shale breaks 746. In some embodiments, heaters 716 are arranged in other patterns. For example, heaters 716 may be arranged in patterns such as, but not limited to, hexagonal patterns, square patterns, or rectangular patterns.

[1013] In the embodiments depicted in FIGS. 130-133, heaters 716 provide heat that mobilizes hydrocarbons (reduces the viscosity of the hydrocarbons) in hydrocarbon layer 460. In certain embodiments, heaters 716 provide heat that reduces the viscosity of the hydrocarbons in hydrocarbon layer 460 below about 0.50 Pa·s (500 cp), below about 0.10 Pa·s (100 cp), or below about 0.05 Pa·s (50 cp). The spacing between heaters 716 and/or the heat output of the heaters may be designed and/or controlled to reduce the viscosity of the hydrocarbons in hydrocarbon layer 460 to desirable values. Heat provided by heaters 716 may be controlled so that little or no

pyrolyzation occurs in hydrocarbon layer 460. Superposition of heat between the heaters may create one or more drainage paths (for example, paths for flow of fluids) between the heaters. In certain embodiments, production wells 206A and/or production wells 206B are located proximate heaters 716 so that heat from the heaters superimposes over the production wells. The superimposition of heat from heaters 716 over production wells 206A and/or production wells 206B creates one or more drainage paths from the heaters to the production wells. In certain embodiments, one or more of the drainage paths converge. For example, the drainage paths may converge at or near a bottommost heater and/or the drainage paths may converge at or near production wells 206A and/or production wells 206B. Fluids mobilized in hydrocarbon layer 460 tend to flow towards the bottommost heaters 716, production wells 206A and/or production wells 206B in the hydrocarbon layer because of gravity and the heat and pressure gradients established by the heaters and/or the production wells. The drainage paths and/or the converged drainage paths allow production wells 206A and/or production wells 206B to collect mobilized fluids in hydrocarbon layer 460.

[1014] In certain embodiments, hydrocarbon layer 460 has sufficient permeability to allow mobilized fluids to drain to production wells 206A and/or production wells 206B. For example, hydrocarbon layer 460 may have a permeability of at least about 0.1 darcy, at least about 1 darcy, at least about 10 darcy, or at least about 100 darcy. In some embodiments, hydrocarbon layer 460 has a relatively large vertical permeability to horizontal permeability ratio (K_v/K_h). For example, hydrocarbon layer 460 may have a K_v/K_h ratio between about 0.01 and about 2, between about 0.1 and about 1, or between about 0.3 and about 0.7.

[1015] In certain embodiments, fluids are produced through production wells 206A located near heaters 716 in the lower portion of hydrocarbon layer 460. In some embodiments, fluids are produced through production wells 206B located below and approximately midway between heaters 716 in the lower portion of hydrocarbon layer 460. At least a portion of production wells 206A and/or production wells 206B may be oriented substantially horizontal in hydrocarbon layer 460 (as shown in FIGS. 130-133, the production wells have horizontal portions that go into and out of the page). Production wells 206A and/or 206B may be located proximate lower portion heaters 716 or the bottommost heaters.

[1016] In some embodiments, production wells 206A are positioned substantially vertically below the bottommost heaters in hydrocarbon layer 460. Production wells 206A may be located below heaters 716 at the bottom vertex of a pattern of the heaters (for example, at the bottom vertex of the triangular pattern of heaters depicted in FIGS. 130-133). Locating production wells 206A substantially vertically below the bottommost heaters may allow for efficient collection of mobilized fluids from hydrocarbon layer 460.

[1017] In certain embodiments, the bottommost heaters are located between about 2 m and about 10 m from the bottom of hydrocarbon layer 460, between about 4 m and about 8 m from the bottom of the hydrocarbon layer, or between about 5 m and about 7 m from the bottom of the hydrocarbon layer. In certain embodiments, production wells 206A and/or production wells 206B are located at a distance from the bottommost heaters 716 that allows heat from the heaters to superimpose over the production wells but at a distance from the heaters that inhibits coking at the production wells. Production wells 206A and/or production wells 206B may be located a distance from the nearest heater (for example, the bottommost heater) of at most ¾ of the spacing between heaters in the pattern of heaters (for example, the triangular pattern of heaters depicted in FIGS. 130-133). In some embodiments, production wells 206A and/or production wells 206B are located a distance from the nearest heater of at most ⅔, at most ½, or at most ⅓ of the spacing between heaters in the pattern of heaters. In certain embodiments, production wells 206A and/or production wells 206B are located between about 2 m and about 10 m from the bottommost heaters, between about 4 m and about 8 m from the bottommost heaters, or between about 5 m and about 7 m from the bottommost heaters. Production wells 206A and/or production wells 206B may be located between about 0.5 m and about 8 m from the bottom of hydrocarbon layer 460, between about 1 m and about 5 m from the bottom of the hydrocarbon layer, or between about 2 m and about 4 m from the bottom of the hydrocarbon layer.

[1018] In some embodiments, at least some production wells 206A are located substantially vertically below heaters 716 near shale break 746, as depicted in FIG. 133. Production wells 206A may be located between heaters 716 and shale break 746 to produce fluids that flow and collect above the shale break. Shale break 746 may be an impermeable barrier in hydrocarbon layer 460. In some embodiments, shale break 746 has a thickness between about 1 m and about 6 m, between about 2 m and about 5 m, or between about 3 m and about 4 m. Production wells 206A between heaters 716 and shale break 746 may produce fluids from the upper portion of hydrocarbon layer 460 (above the shale break) and production wells 206A below the bottommost heaters in the hydrocarbon layer may produce fluids from the lower portion of the hydrocarbon layer (below the shale break), as depicted in FIG. 133. In some embodiments, two or more shale breaks may exist in a hydrocarbon layer. In such an embodiment, production wells are placed at or near each of the shale breaks to produce fluids flowing and collecting above the shale breaks.

[1019] In some embodiments, shale break 746 breaks down (is desiccated) as the shale break is heated by heaters 716 on either side of the shale break. As shale break 746 breaks down, the permeability of the shale break increases and the shale break allows fluids to flow through the shale break. Once fluids are able to flow through shale break 746, production wells above the

shale break may not be needed for production as fluids can flow to production wells at or near the bottom of hydrocarbon layer 460 and be produced there.

[1020] In certain embodiments, the bottommost heaters above shale break 746 are located between about 2 m and about 10 m from the shale break, between about 4 m and about 8 m from the bottom of the shale break, or between about 5 m and about 7 m from the shale break. Production wells 206A may be located between about 2 m and about 10 m from the bottommost heaters above shale break 746, between about 4 m and about 8 m from the bottommost heaters above the shale break, or between about 5 m and about 7 m from the bottommost heaters above the shale break. Production wells 206A may be located between about 0.5 m and about 8 m from shale break 746, between about 1 m and about 5 m from the shale break, or between about 2 m and about 4 m from the shale break.

[1021] In some embodiments, heat is provided in production wells 206A and/or production wells 206B, depicted in FIGS. 130-133. Providing heat in production wells 206A and/or production wells 206B may maintain and/or enhance the mobility of the fluids in the production wells. Heat provided in production wells 206A and/or production wells 206B may superpose with heat from heaters 716 to create the flow path from the heaters to the production wells. In some embodiments, production wells 206A and/or production wells 206B include a pump to remove fluids to the surface of the formation. In some embodiments, the viscosity of fluids (oil) in production wells 206A and/or production wells 206B is lowered using heaters and/or diluent injection (for example, using a conduit in the production wells for injecting the diluent).

[1022] In certain embodiments, in situ heat treatment of the relatively permeable formation containing hydrocarbons (for example, the tar sands formation) includes heating the formation to visbreaking temperatures. For example, the formation may be heated to temperatures between about 100 °C and 260 °C, between about 150 °C and about 250 °C, or between about 200 °C and about 240 °C. At visbreaking temperatures, fluids in the formation have a reduced viscosity (versus their initial viscosity at initial formation temperature) that allows fluids to flow in the formation. The visbroken fluids may have API gravities that are relatively low (for example, at most about 10°, about 12°, or about 15° API gravity), but the API gravities are higher than the API gravity of non-visbroken fluid from the formation. The non-visbroken fluid from the formation may have an API gravity of 7° or less.

[1023] In some embodiments, heaters in the formation are operated at full power output to heat the formation to visbreaking temperatures or higher temperatures. Operating at full power may rapidly increase the pressure in the formation. In certain embodiments, fluids are produced from the formation to maintain a pressure in the formation below a selected pressure as the temperature of the formation increases. In some embodiments, the selected pressure is a fracture

pressure of the formation. In certain embodiments, the selected pressure is between about 1000 kPa and about 15000 kPa, between about 2000 kPa and about 10000 kPa, or between about 2500 kPa and about 5000 kPa. The fluids produced from the formation may be visbroken, mobilized fluids, and/or pyrolyzed fluids. Maintaining the pressure as close to the fracture pressure as possible may minimize the number of production wells needed for producing fluids from the formation.

[1024] In some embodiments, after the formation reaches visbreaking temperatures, the pressure in the formation is reduced. In certain embodiments, the pressure in the formation is reduced at temperatures above visbreaking temperatures. Reducing the pressure at higher temperatures allows more of the hydrocarbons in the formation to be converted to higher quality hydrocarbons by visbreaking and/or pyrolysis. Allowing the formation to reach higher temperatures before pressure reduction, however, may increase the amount of carbon dioxide produced and/or the amount of coking in the formation. For example, in some formations, coking of bitumen (at pressures above 700 kPa) begins at about 280 °C and reaches a maximum rate at about 340 °C. At pressures below about 700 kPa, the coking rate in the formation is minimal. Allowing the formation to reach higher temperatures before pressure reduction may decrease the amount of hydrocarbons produced from the formation.

[1025] In certain embodiments, the temperature in the formation (for example, an average temperature of the formation) when the pressure in the formation is reduced is selected to balance one or more factors. The factors considered may include: the quality of hydrocarbons produced, the amount of hydrocarbons produced, the amount of carbon dioxide produced, the amount hydrogen sulfide produced, the degree of coking in the formation, and/or the amount of water produced. Experimental assessments using formation samples and/or simulated assessments based on the formation properties may be used to assess results of treating the formation using the in situ heat treatment process. These results may be used to determine a selected temperature, or temperature range, for when the pressure in the formation is to be reduced. The selected temperature, or temperature range, may also be affected by factors such as, but not limited to, hydrocarbon or oil market conditions and other economic factors. In certain embodiments, the selected temperature is in a range between about 275 °C and about 305 °C, between about 280 °C and about 300 °C, or between about 285 °C and about 295 °C.

[1026] In certain embodiments, an average temperature in the formation is assessed from an analysis of fluids produced from the formation. For example, the average temperature of the formation may be assessed from an analysis of the fluids that have been produced to maintain the pressure in the formation below the fracture pressure of the formation.

[1027] In some embodiments, values of the hydrocarbon isomer shift in fluids (for example, gases) produced from the formation is used to indicate the average temperature in the formation. Experimental analysis and/or simulation may be used to assess one or more hydrocarbon isomer shifts and relate the values of the hydrocarbon isomer shifts to the average temperature in the formation. The assessed relation between the hydrocarbon isomer shifts and the average temperature may then be used in the field to assess the average temperature in the formation by monitoring one or more of the hydrocarbon isomer shifts in fluids produced from the formation. In some embodiments, the pressure in the formation is reduced when the monitored hydrocarbon isomer shift reaches a selected value. The selected value of the hydrocarbon isomer shift may be chosen based on the selected temperature, or temperature range, in the formation for reducing the pressure in the formation and the assessed relation between the hydrocarbon isomer shift and the average temperature. Examples of hydrocarbon isomer shifts that may be assessed include, but are not limited to, n-butane-$\delta^{13}C_4$ percentage versus propane- $\delta^{13}C_3$ percentage, n-pentane- $\delta^{13}C_5$ percentage versus propane- $\delta^{13}C_3$ percentage, n-pentane- $\delta^{13}C_5$ percentage versus n-butane- $\delta^{13}C_4$ percentage, and i-pentane- $\delta^{13}C_5$ percentage versus i-butane- $\delta^{13}C_4$ percentage. In some embodiments, the hydrocarbon isomer shift in produced fluids is used to indicate the amount of conversion (for example, amount of pyrolysis) that has taken place in the formation.

[1028] In some embodiments, weight percentages of saturates in fluids produced from the formation is used to indicate the average temperature in the formation. Experimental analysis and/or simulation may be used to assess the weight percentage of saturates as a function of the average temperature in the formation. For example, SARA (**S**aturates, **A**romatics, **R**esins, and **A**sphaltenes) analysis (sometimes referred to as Asphaltene/Wax/Hydrate Deposition analysis) may be used to assess the weight percentage of saturates in a sample of fluids from the formation. In some formations, the weight percentage of saturates has a linear relationship to the average temperature in the formation. The relation between the weight percentage of saturates and the average temperature may then be used in the field to assess the average temperature in the formation by monitoring the weight percentage of saturates in fluids produced from the formation. In some embodiments, the pressure in the formation is reduced when the monitored weight percentage of saturates reaches a selected value. The selected value of the weight percentage of saturates may be chosen based on the selected temperature, or temperature range, in the formation for reducing the pressure in the formation and the relation between the weight percentage of saturates and the average temperature.

[1029] In some embodiments, weight percentages of n-C_7 in fluids produced from the formation is used to indicate the average temperature in the formation. Experimental analysis and/or simulation may be used to assess the weight percentages of n-C_7 as a function of the average

temperature in the formation. In some formations, the weight percentages of n-C_7 has a linear relationship to the average temperature in the formation. The relation between the weight percentages of n-C_7 and the average temperature may then be used in the field to assess the average temperature in the formation by monitoring the weight percentages of n-C_7 in fluids produced from the formation. In some embodiments, the pressure in the formation is reduced when the monitored weight percentage of n-C_7 reaches a selected value. The selected value of the weight percentage of n-C_7 may be chosen based on the selected temperature, or temperature range, in the formation for reducing the pressure in the formation and the relation between the weight percentage of n-C_7 and the average temperature.

[1030] The pressure in the formation may be reduced by producing fluids (for example, visbroken fluids and/or mobilized fluids) from the formation. In some embodiments, the pressure is reduced below a pressure at which fluids coke in the formation to inhibit coking at pyrolysis temperatures. For example, the pressure is reduced to a pressure below about 1000 kPa, below about 800 kPa, or below about 700 kPa (for example, about 690 kPa). In certain embodiments, the selected pressure is at least about 100 kPa, at least about 200 kPa, or at least about 300 kPa. The pressure may be reduced to inhibit coking of asphaltenes or other high molecular weight hydrocarbons in the formation. In some embodiments, the pressure may be maintained below a pressure at which water passes through a liquid phase at downhole (formation) temperatures to inhibit liquid water and dolomite reactions. After reducing the pressure in the formation, the temperature may be increased to pyrolysis temperatures to begin pyrolyzation and/or upgrading of fluids in the formation. The pyrolyzed and/or upgraded fluids may be produced from the formation.

[1031] In certain embodiments, the amount of fluids produced at temperatures below visbreaking temperatures, the amount of fluids produced at visbreaking temperatures, the amount of fluids produced before reducing the pressure in the formation, and/or the amount of upgraded or pyrolyzed fluids produced may be varied to control the quality and amount of fluids produced from the formation and the total recovery of hydrocarbons from the formation. For example, producing more fluid during the early stages of treatment (for example, producing fluids before reducing the pressure in the formation) may increase the total recovery of hydrocarbons from the formation while reducing the overall quality (lowering the overall API gravity) of fluid produced from the formation. The overall quality is reduced because more heavy hydrocarbons are produced by producing more fluids at the lower temperatures. Producing less fluids at the lower temperatures may increase the overall quality of the fluids produced from the formation but may lower the total recovery of hydrocarbons from the formation. The total recovery may be lower

because more coking occurs in the formation when less fluids are produced at lower temperatures.

[1032] In certain embodiments, the formation is heated using isolated cells of heaters (cells or sections of the formation that are not interconnected for fluid flow). The isolated cells may be created by user larger heater spacings in the formation. For example, large heater spacings may be used in the embodiments depicted in FIGS. 130-133. These isolated cells may be produced during early stages of heating (for example, at temperatures below visbreaking temperatures). Because the cells are isolated from other cells in the formation, the pressures in the isolated cells are high and more liquids are producible from the isolated cells. Thus, more liquids may be produced from the formation and a higher total recovery of hydrocarbons may be reached. During later stages of heating, the heat gradient may interconnect the isolated cells and pressures in the formation will drop.

[1033] In certain embodiments, the heat gradient in the formation is modified so that a gas cap is created at or near an upper portion of the hydrocarbon layer. For example, the heat gradient made by heaters 716 depicted in the embodiments depicted in FIGS. 130-133 may be modified to create the gas cap at or near overburden 458 of hydrocarbon layer 460. The gas cap may push or drive liquids to the bottom of the hydrocarbon layer so that more liquids may be produced from the formation. In situ generation of the gas cap may be more efficient than introducing pressurized fluid into the formation. The in situ generated gas cap applies force evenly through the formation with little or no channeling or fingering that may reduce the effectiveness of introduced pressurized fluid.

[1034] In certain embodiments, the number and/or location of production wells in the formation is varied based on the viscosity of the formation. More or less production wells may be located in zones of the formation with different viscosities. The viscosities of the zones may be assessed before placing the production wells in the formation, before heating the formation, and/or after heating the formation. In some embodiments, more production wells are located in zones in the formation that have lower viscosities. For example, in certain formations, upper portions, or zones, of the formation may have lower viscosities. Thus, more production wells may be located in the upper zones. Locating production wells in the less viscous zones of the formation allows for better pressure control in the formation and/or producing higher quality (more upgraded) oil from the formation.

[1035] In some embodiments, zones in the formation with different assessed viscosities are heated at different rates. In certain embodiments, zones in the formation with higher viscosities are heated at higher heating rates than zones with lower viscosities. Heating the zones with

higher viscosities at the higher heating rates mobilizes and/or upgrades these zones at a faster rate so that these zones may "catch up" in viscosity and/or quality to the slower heated zones.

[1036] In some embodiments, the heater spacing is varied to provide different heating rates to zones in the formation with different assessed viscosities. For example, denser heater spacings (less spaces between heaters) may be used in zones with higher viscosities to heat these zones at higher heating rates. In some embodiments, a production well (for example, a substantially vertical production well) is located in the zones with denser heater spacings and higher viscosities. The production well may be used to remove fluids from the formation and relieve pressure from the higher viscosity zones. In some embodiments, one or more substantially vertical openings, or production wells, are located in the higher viscosity zones to allow fluids to drain in the higher viscosity zones. The draining fluids may be produced from the formation through production wells located near the bottom of the higher viscosity zones.

[1037] In certain embodiments, production wells are located in more than one zone in the formation. The zones may have different initial permeabilities. In certain embodiments, a first zone has an initial permeability of at least about 1 darcy and a second zone has an initial permeability of at most about 0.1 darcy. In some embodiments, the first zone has an initial permeability of between about 1 darcy and about 10 darcy. In some embodiments, the second zone has an initial permeability between about 0.01 darcy and 0.1 darcy. The zones may be separated by a substantially impermeable barrier (with an initial permeability of at most about 10 μdarcy or less). Having the production well located in both zones allows for fluid communication (permeability) between the zones and/or pressure equalization between the zones.

[1038] In some embodiments, openings (for example, substantially vertical openings) are formed between zones with different initial permeabilities that are separated by a substantially impermeable barrier. Bridging the zones with the openings allows for fluid communication (permeability) between the zones and/or pressure equalization between the zones. In some embodiments, openings in the formation (such as pressure relief openings and/or production wells) allow gases or low viscosity fluids to rise in the openings. As the gases or low viscosity fluids rise, the fluids may condense or increase viscosity in the openings so that the fluids drain back down the openings to be further upgraded in the formation. Thus, the openings may act as heat pipes by transferring heat from the lower portions to the upper portions where the fluids condense. The wellbores may be packed and sealed near or at the overburden to inhibit transport of formation fluid to the surface.

[1039] In some embodiments, production of fluids is continued after reducing and/or turning off heating of the formation. The formation may be heated for a selected time. For example, the

formation may be heated until it reaches a selected average temperature. Production from the formation may continue after the selected time. Continuing production may produce more fluid from the formation as fluids drain towards the bottom of the formation and/or fluids is upgraded by passing by hot spots in the formation. In some embodiments, a horizontal production well is located at or near the bottom of the formation (or a zone of the formation) to produce fluids after heating is turned down and/or off.

[1040] In certain embodiments, initially produced fluids (for example, fluids produced below visbreaking temperatures), fluids produced at visbreaking temperatures, and/or other viscous fluids produced from the formation are blended with diluent to produce fluids with lower viscosities. In some embodiments, the diluent includes upgraded or pyrolyzed fluids produced from the formation. In some embodiments, the diluent includes upgraded or pyrolyzed fluids produced from another portion of the formation or another formation. In certain embodiments, the amount of fluids produced at temperatures below visbreaking temperatures and/or fluids produced at visbreaking temperatures that are blended with upgraded fluids from the formation is adjusted to create a fluid suitable for transportation and/or use in a refinery. The amount of blending may be adjusted so that the fluid has chemical and physical stability. Maintaining the chemical and physical stability of the fluid may allow the fluid to be transported, reduce pre-treatment processes at a refinery and/or reduce or eliminate the need for adjusting the refinery process to compensate for the fluid.

[1041] In certain embodiments, formation conditions (for example, pressure and temperature) and/or fluid production are controlled to produce fluids with selected properties. For example, formation conditions and/or fluid production may be controlled to produce fluids with a selected API gravity and/or a selected viscosity. The selected API gravity and/or selected viscosity may be produced by combining fluids produced at different formation conditions (for example, combining fluids produced at different temperatures during the treatment as described above). As an example, formation conditions and/or fluid production may be controlled to produce fluids with an API gravity of about 19° and a viscosity of about 0.35 Pa·s (350 cp) at 19 °C.

[1042] In some embodiments, formation conditions and/or fluid production is controlled so that water (for example, connate water) is recondensed in the treatment area. Recondensing water in the treatment area keeps the heat of condensation in the formation. In addition, having liquid water in the formation may increase mobility of liquid hydrocarbons (oil) in the formation. Liquid water may wet rock or other strata in the formation by occupying pores or corners in the strata and creating a slick surface that moves liquid hydrocarbons more readily through the formation.

[1043] In certain embodiments, a drive process (for example, a steam injection process such as cyclic steam injection, a steam assisted gravity drainage process (SAGD), a solvent injection process, a vapor solvent and SAGD process, or a carbon dioxide injection process) is used to treat the tar sands formation in addition to the in situ heat treatment process. In some embodiments, heaters are used to create high permeability zones (or injection zones) in the formation for the drive process. Heaters may be used to create a mobilization geometry or production network in the formation to allow fluids to flow through the formation during the drive process. For example, heaters may be used to create drainage paths between the heaters and production wells for the drive process. In some embodiments, the heaters are used to provide heat during the drive process. The amount of heat provided by the heaters may be small compared to the heat input from the drive process (for example, the heat input from steam injection).

[1044] In some embodiments, the in situ heat treatment process creates or produces the drive fluid in situ. The in situ produced drive fluid may move through the formation and move mobilized hydrocarbons from one portion of the formation to another portion of the formation.

[1045] In some embodiments, the in situ heat treatment process may provide less heat to the formation (for example, use a wider heater spacing) if the in situ heat treatment process is followed by the drive process. The drive process may be used to increase the amount of heat provided to the formation to compensate for the loss of heat injection.

[1046] In some embodiments, the drive process is used to treat the formation and produce hydrocarbons from the formation. The drive process may recover a low amount of oil in place from the formation (for example, less than 20% recovery of oil in place from the formation). The in situ heat treatment process may be used following the drive process to increase the recovery of oil in place from the formation. In some embodiments, the drive process preheats the formation for the in situ heat treatment process. In some embodiments, the formation is treated using the in situ heat treatment process a significant time after the formation has been treated using the drive process. For example, the in situ heat treatment process is used 1 year, 2 years, 3 years, or longer after a formation has been treated using the drive process. The in situ heat treatment process may be used on formations that have been left dormant after the drive process treatment because further hydrocarbon production using the drive process is not possible and/or not economically feasible. In some embodiments, the formation remains at least somewhat preheated from the drive process even after the significant time.

[1047] In some embodiments, heaters are used to preheat the formation for the drive process. For example, heaters may be used to create injectivity in the formation for a drive fluid. The heaters may create high mobility zones (or injection zones) in the formation for the drive process.

In certain embodiments, heaters are used to create injectivity in formations with little or no initial injectivity. Heating the formation may create a mobilization geometry or production network in the formation to allow fluids to flow through the formation for the drive process. For example, heaters may be used to create a fluid production network between a horizontal heater and a vertical production well. The heaters used to preheat the formation for the drive process may also be used to provide heat during the drive process.

[1048] FIG. 134 depicts a top view representation of an embodiment for preheating using heaters for the drive process. Injection wells 748 and production wells 206 are substantially vertical wells. Heaters 716 are long substantially horizontal heaters positioned so that the heaters pass in the vicinity of injection wells 748. Heaters 716 intersect the vertical well patterns slightly displaced from the vertical wells.

[1049] The vertical location of heaters 716 with respect to injection wells 748 and production wells 206 depends on, for example, the vertical permeability of the formation. In formations with at least some vertical permeability, injected steam will rise to the top of the permeable layer in the formation. In such formations, heaters 716 may be located near the bottom of hydrocarbon layer 460, as shown in FIG. 135. In formations with very low vertical permeabilities, more than one horizontal heater may be used with the heaters stacked substantially vertically or with heaters at varying depths in the hydrocarbon layer (for example, heater patterns as shown in FIGS. 130-133). The vertical spacing between the horizontal heaters in such formations may correspond to the distance between the heaters and the injection wells. Heaters 716 are located in the vicinity of injection wells 748 and/or production wells 206 so that sufficient energy is delivered by the heaters to provide flow rates for the drive process that are economically viable. The spacing between heaters 716 and injection wells 748 or production wells 206 may be varied to provide an economically viable drive process. The amount of preheating may also be varied to provide an economically viable process.

[1050] Some formations with little or no initial injectivity (such as karsted formations or karsted layers in formations) may have tight vugs in one or more layers of the formations. The tight vugs may be vugs filled with viscous fluids such as bitumen or heavy oil. In some embodiments, the vugs have a porosity of at least about 20 porosity units, at least about 30 porosity units, or at least about 35 porosity units. The formation may have a porosity of at most about 15 porosity units, at most about 10 porosity units, or at most about 5 porosity units. The tight vugs inhibit steam or other fluids from being injected into the formation or the layers with tight vugs. In certain embodiments, the karsted formation or karsted layers of the formation are treated using the in situ heat treatment process. Heating of these formations or layers may decrease the viscosity of the fluids in the tight vugs and allow the fluids to drain (for example, mobilize the fluids).

[1051] In certain embodiments, only the karsted layers of the formation are treated using the in situ heat treatment process. Other non-karsted layers of the formation may be used as seals for the in situ heat treatment process.

[1052] In some embodiments, the drive process is used after the in situ heat treatment of the karsted formation or karsted layers. In some embodiments, heaters are used to preheat the karsted formation or karsted layers to create injectivity in the formation.

[1053] In certain embodiments, the karsted formation or karsted layers are heated to temperatures below the decomposition temperature of rock (for example, dolomite) in the formation (for example, temperatures at most about 400 °C). In some embodiments, the karsted formation or karsted layers are heated to temperatures above the decomposition temperature of dolomite in the formation. At temperatures above the dolomite decomposition temperature, the dolomite may decompose to produce carbon dioxide. The decomposition of the dolomite and the carbon dioxide production may create permeability in the formation and mobilize viscous fluids in the formation. In some embodiments, the produced carbon dioxide is maintained in the formation to produce a gas cap in the formation. The carbon dioxide may be allowed to rise to the upper portions of the karsted layers to produce the gas cap.

[1054] In some embodiments, heaters are used to produce and/or maintain the gas cap in the formation for the in situ heat treatment process and/or the drive process. The gas cap may drive fluids from upper portions to lower portions of the formation and/or from portions of the formation towards portions of the formation at lower pressures (for example, portions with production wells). In some embodiments, little or no heating is provided in the portions of the formation with the gas cap. In some embodiments, heaters in the gas cap are turned down and/or off after formation of the gas cap. Using less heating in the gas cap may reduce the energy input into the formation and increase the efficiency of the in situ heat treatment process and/or the drive process. In some embodiments, production wells and/or heater wells that are located in the gas cap portion of the formation may be used for injection of fluid (for example, steam) to maintain the gas cap.

[1055] In some embodiments, the production front of the drive process follows behind the heat front of the in situ heat treatment process. In some embodiments, areas behind the production front are further heated to produce more fluids from the formation. Further heating behind the production front may also maintain the gas cap behind the production front and/or maintain quality in the production front of the drive process.

[1056] In certain embodiments, the drive process is used before the in situ heat treatment of the formation. In some embodiments, the drive process is used to mobilize fluids in a first section of the formation. The mobilized fluids may then be pushed into a second section by heating the first

section with heaters. Fluids may be produced from the second section. In some embodiments, the fluids in the second section are pyrolyzed and/or upgraded using the heaters.

[1057] In formations with low permeabilities, the drive process may be used to create a "gas cushion" or pressure sink before the in situ heat treatment process. The gas cushion may inhibit pressures from increasing quickly to fracture pressure during the in situ heat treatment process. The gas cushion may provide a path for gases to escape or travel during early stages of heating during the in situ heat treatment process.

[1058] In some embodiments, the drive process (for example, the steam injection process) is used to mobilize fluids before the in situ heat treatment process. Steam injection may be used to get hydrocarbons (oil) away from rock or other strata in the formation. The steam injection may mobilize the oil without significantly heating the rock.

[1059] In some embodiments, injection of a fluid (for example, steam or carbon dioxide) may consume heat in the formation and cool the formation depending on the pressure in the formation. In some embodiments, the injected fluid is used to recover heat from the formation. The recovered heat may be used in surface processing of fluids and/or to preheat other portions of the formation using the drive process.

[1060] FIG. 136 depicts a representation of an embodiment for producing hydrocarbons from a hydrocarbon containing formation (for example, a tar sands formation). Hydrocarbon layer 460 includes one or more portions with heavy hydrocarbons. Hydrocarbons may be produced from hydrocarbon layer 460 using more than one process. In certain embodiments, hydrocarbons are produced from a first portion of hydrocarbon layer 460 using a steam injection process (for example, cyclic steam injection or steam-assisted gravity drainage) and a second portion of the hydrocarbon layer using an in situ heat treatment process. In the steam injection process, steam is injected into the first portion of hydrocarbon layer 460 through injection well 748. First hydrocarbons are produced from the first portion through production well 206A. The first hydrocarbons include hydrocarbons mobilized by the injection of steam. In certain embodiments, the first hydrocarbons have an API gravity of at most 15°, at most 10°, at most 8°, or at most 6°.

[1061] Heaters 716 are used to heat the second portion of hydrocarbon layer 460 to mobilization, visbreaking, and/or pyrolysis temperatures. Second hydrocarbons are produced from the second portion through production well 206B. In some embodiments, the second hydrocarbons include at least some pyrolyzed hydrocarbons. In certain embodiments, the second hydrocarbons have an API gravity of at least 15°, at least 20°, or at least 25°.

[1062] In some embodiments, the first portion of hydrocarbon layer 460 is treated using heaters after the steam injection process. Heaters may be used to increase the temperature of the first

portion and/or treat the first portion using an in situ heat treatment process. Second hydrocarbons (including at least some pyrolyzed hydrocarbons) may be produced from the first portion through production well 206A.

[1063] In some embodiments, the second portion of hydrocarbon layer 460 is treated using the steam injection process before using heaters 716 to treat the second portion. The steam injection process may be used to produce some fluids (for example, first hydrocarbons or hydrocarbons mobilized by the steam injection) through production well 206B from the second portion and/or preheat the second portion before using heaters 716. In some embodiments, the steam injection process may be used after using heaters 716 to treat the first portion and/or the second portion.

[1064] Producing hydrocarbons through both processes increases the total recovery of hydrocarbons from hydrocarbon layer 460 and may be more economical than using either process alone. In some embodiments, the first portion is treated with the in situ heat treatment process after the steam injection process is completed. For example, after the steam injection process no longer produces viable amounts of hydrocarbon from the first portion, the in situ heat treatment process may be used on the first portion.

[1065] Steam is provided to injection well 748 from facility 750. Facility 750 is a steam and electricity cogeneration facility. Facility 750 may burn hydrocarbons in generators to make electricity. Facility 750 may burn gaseous and/or liquid hydrocarbons to make electricity. The electricity generated is used to provide electrical power for heaters 716. Waste heat from the generators is used to make steam. In some embodiments, some of the hydrocarbons produced from the formation are used to provide gas for heaters 716, if the heaters utilize gas to provide heat to the formation. The amount of electricity and steam generated by facility 750 may be controlled to vary the production rate and/or quality of hydrocarbons produced from the first portion and/or the second portion of hydrocarbon layer 460. The production rate and/or quality of hydrocarbons produced from the first portion and/or the second portion may be varied to produce a selected API gravity in a mixture made by blending the first hydrocarbons with the second hydrocarbons. The first hydrocarbon and the second hydrocarbons may be blended after production to produce the selected API gravity. The production from the first portion and/or the second portion may be varied in response to changes in the marketplace for either first hydrocarbons, second hydrocarbons, and/or a mixture of the first and second hydrocarbons.

[1066] First hydrocarbons produced from production well 206A and/or second hydrocarbons produced from production well 206B may be used as fuel for facility 750. In some embodiments, first hydrocarbons and/or second hydrocarbons are treated (for example, removing undesirable products) before being used as fuel for facility 750. The amount of first hydrocarbons and second hydrocarbons used as fuel for facility 750 may be determined, for example, by economics

for the overall process, the marketplace for either first or second hydrocarbons, availability of treatment facilities for either first or second hydrocarbons, and/or transportation facilities available for either first or second hydrocarbons. In some embodiments, most or all the hydrocarbon gas produced from hydrocarbon layer 460 is used as fuel for facility 750. Burning all the hydrocarbon gas in facility 750 eliminates the need for treatment and/or transportation of gases produced from hydrocarbon layer 460.

[1067] The produced first hydrocarbons and the second hydrocarbons may be treated and/or blended in facility 752. In some embodiments, the first and second hydrocarbons are blended to make a mixture that is transportable through a pipeline. In some embodiments, the first and second hydrocarbons are blended to make a mixture that is useable as a feedstock for a refinery. The amount of first and second hydrocarbons produced may be varied based on changes in the requirements for treatment and/or blending of the hydrocarbons. In some embodiments, treated hydrocarbons are used in facility 750.

[1068] In some embodiments, the steam injection process and the in situ heat treatment process (for example, the in situ conversion process) are used synergistically in different layers (for example, vertically displaced layers) in the formation. For example, in a karsted formation, different zones or layers in the formation may have different oil saturations, water saturations, porosities, and/or permeabilities. Some layers may have good steam injectivities while others have near zero steam injectivity. The steam injectivity may depend on the water saturation of the zone and the permeability. Thus, varying the use of the steam injection process and the in situ heat treatment process in these layers may be economically advantageous by, for example, producing more hydrocarbons with less energy input into the formation. The steam injection process may include steam drive, cyclic steam injection, SAGD, or other process of steam injection into the formation.

[1069] FIG. 137 depicts a representation of an embodiment for producing hydrocarbons from multiple layers in a tar sands formation. Hydrocarbon layers 460A,B,C include one or more portions with heavy hydrocarbons. Hydrocarbon layers 460A,B,C may have different oil saturations, water saturations, porosities, and/or permeabilities. In one embodiment, hydrocarbon layers 460A,C have lower oil saturations, higher water saturations, and lower porosities than hydrocarbon layer 460B. The steam injection process may be used in hydrocarbon layers 460A,C using injection wells 748A,C and production wells 206A,C. The in situ heat treatment process may be used in hydrocarbon layer 460B using heaters 716 and production well 206B. In some embodiments, the in situ heat treatment process is used in hydrocarbon layer 460B, which has high oil saturation and low steam injectivity. After the in situ heat treatment of hydrocarbon layer 460B, the layer may have steam injectivity and be treated using the steam injection process.

[1070] Injecting steam into hydrocarbon layers 460A,C above and below hydrocarbon layer 460B may increase the efficiency of producing hydrocarbons from the formation. Steam injection in hydrocarbon layers 460A,C lowers the viscosity and increases the pressures in these layers so that hydrocarbons move into hydrocarbon layer 460B. Heat from hydrocarbon layer 460B may conduct and/or convect into hydrocarbon layers 460A,C and preheat these layers to lower the oil viscosity and/or increase the steam injectivity in hydrocarbon layers 460A,C. Additionally, some steam may rise from hydrocarbon layer 460C into hydrocarbon layer 460B. This steam may provide additional heat and increased mobilization in hydrocarbon layer 460B. The steam injection process and/or the in situ heat treatment process may be used (for example, varied) as described above for the embodiment depicted in FIG. 136. Hydrocarbons produced from any of hydrocarbon layers 460A,B,C may be used and/or processed in facility 750 and/or facility 752, as described above for the embodiment depicted in FIG. 136.

[1071] In some embodiments, impermeable shale layers exist between hydrocarbon layer 460B and hydrocarbon layers 460A,C. Using the in situ heat treatment process on hydrocarbon layer 460B may desiccate the shale layers and increase the permeability of the shale layers to allow fluid flux through the shale layers. This increased permeability in the shale layers allows mobilized hydrocarbons to flow from hydrocarbon layer 460A into hydrocarbon layer 460B. These hydrocarbons may be upgraded and produced in hydrocarbon layer 460B.

[1072] FIG. 138 depicts an embodiment for heating and producing from the formation with the temperature limited heater in a production wellbore. Production conduit 754 is located in wellbore 756. In certain embodiments, a portion of wellbore 756 is located substantially horizontally in formation 758. In some embodiments, the wellbore is located substantially vertically in the formation. In an embodiment, wellbore 756 is an open wellbore (an uncased wellbore). In some embodiments, the wellbore has a casing or liner with perforations or openings to allow fluid to flow into the wellbore.

[1073] Conduit 754 may be made from carbon steel or more corrosion resistant materials such as stainless steel. Conduit 754 may include apparatus and mechanisms for gas lifting or pumping produced oil to the surface. For example, conduit 754 includes gas lift valves used in a gas lift process. Examples of gas lift control systems and valves are disclosed in U.S. Patent No. 6,715,550 to Vinegar et al. and U.S. Patent Application Publication Nos. 2002-0036085 to Bass et al. and 2003-0038734 to Hirsch et al. Conduit 754 may include one or more openings (perforations) to allow fluid to flow into the production conduit. In certain embodiments, the openings in conduit 754 are in a portion of the conduit that remains below the liquid level in wellbore 756. For example, the openings are in a horizontal portion of conduit 754.

[1074] Heater 760 is located in conduit 754, as shown in FIG. 138. In some embodiments, heater 760 is located outside conduit 754, as shown in FIG. 139. The heater located outside the production conduit may be coupled (strapped) to the production conduit. In some embodiments, more than one heater (for example, two, three, or four heaters) are placed about conduit 754. The use of more than one heater may reduce bowing or flexing of the production conduit caused by heating on only one side of the production conduit. In an embodiment, heater 760 is a temperature limited heater. Heater 760 provides heat to reduce the viscosity of fluid (such as oil or hydrocarbons) in and near wellbore 756. In certain embodiments, heater 760 raises the temperature of the fluid in wellbore 756 up to a temperature of 250 °C or less (for example, 225 °C, 200 °C, or 150 °C). Heater 760 may be at higher temperatures (for example, 275 °C, 300 °C, or 325 °C) because the heater provides heat to conduit 754 and there is some temperature differential between the heater and the conduit. Thus, heat produced from the heater does not raise the temperature of fluids in the wellbore above 250 °C.

[1075] In certain embodiments, heater 760 includes ferromagnetic materials such as Carpenter Temperature Compensator "32", Alloy 42-6, Alloy 52, Invar 36, or other iron-nickel or iron-nickel-chromium alloys. In certain embodiments, nickel or nickel-chromium alloys are used in heater 760. In some embodiments, heater 760 includes a composite conductor with a more highly conductive material such as copper on the inside of the heater to improve the turndown ratio of the heater. Heat from heater 760 heats fluids in or near wellbore 756 to reduce the viscosity of the fluids and increase a production rate through conduit 754.

[1076] In certain embodiments, portions of heater 760 above the liquid level in wellbore 756 (such as the vertical portion of the wellbore depicted in FIGS. 138 and 139) have a lower maximum temperature than portions of the heater located below the liquid level. For example, portions of heater 760 above the liquid level in wellbore 756 may have a maximum temperature of 100 °C while portions of the heater located below the liquid level have a maximum temperature of 250 °C. In certain embodiments, such a heater includes two or more ferromagnetic sections with different Curie temperatures and/or phase transformation temperature ranges to achieve the desired heating pattern. Providing less heat to portions of wellbore 756 above the liquid level and closer to the surface may save energy.

[1077] In certain embodiments, heater 760 is electrically isolated on the heater's outside surface and allowed to move freely in conduit 754. In some embodiments, electrically insulating centralizers are placed on the outside of heater 760 to maintain a gap between conduit 754 and the heater.

[1078] In some embodiments, heater 760 is cycled (turned on and off) so that fluids produced through conduit 754 are not overheated. In an embodiment, heater 760 is turned on for a

specified amount of time until a temperature of fluids in or near wellbore 756 reaches a desired temperature (for example, the maximum temperature of the heater). During the heating time (for example, 10 days, 20 days, or 30 days), production through conduit 754 may be stopped to allow fluids in the formation to "soak" and obtain a reduced viscosity. After heating is turned off or reduced, production through conduit 754 is started and fluids from the formation are produced without excess heat being provided to the fluids. During production, fluids in or near wellbore 756 will cool down without heat from heater 760 being provided. When the fluids reach a temperature at which production significantly slows down, production is stopped and heater 760 is turned back on to reheat the fluids. This process may be repeated until a desired amount of production is reached. In some embodiments, some heat at a lower temperature is provided to maintain a flow of the produced fluids. For example, low temperature heat (for example, 100 °C, 125 °C, or 150 °C) may be provided in the upper portions of wellbore 756 to keep fluids from cooling to a lower temperature.

[1079] FIG. 140 depicts an embodiment of a heating/production assembly that may be located in a wellbore for gas lifting. Heating/production assembly 762 may be located in a wellbore in the formation (for example, wellbore 756 depicted in FIGS. 138 or 139). Conduit 754 is located inside casing 530. In an embodiment, conduit 754 is coiled tubing such as 6 cm diameter coiled tubing. Casing 530 has a diameter between 10 cm and 25 cm (for example, a diameter of 14 cm, 16 cm, or 18 cm). Heater 760 is coupled to an end of conduit 754. In some embodiments, heater 760 is located inside conduit 754. In some embodiments, heater 760 is a resistive portion of conduit 754. In some embodiments, heater 760 is coupled to a length of conduit 754.

[1080] Opening 764 is located at or near a junction of heater 760 and conduit 754. In some embodiments, opening 764 is a slot or a slit in conduit 754. In some embodiments, opening 764 includes more than one opening in conduit 754. Opening 764 allows production fluids to flow into conduit 754 from a wellbore. Perforated casing 766 allows fluids to flow into the heating/production assembly 762. In certain embodiments, perforated casing 766 is a wire wrapped screen. In one embodiment, perforated casing 766 is a 9 cm diameter wire wrapped screen.

[1081] Perforated casing 766 may be coupled to casing 530 with packing material 532. Packing material 532 inhibits fluids from flowing into casing 530 from outside perforated casing 766. Packing material 532 may also be placed inside casing 530 to inhibit fluids from flowing up the annulus between the casing and conduit 754. Seal assembly 768 is used to seal conduit 754 to packing material 532. Seal assembly 768 may fix a position of conduit 754 along a length of a wellbore. In some embodiments, seal assembly 768 allows for unsealing of conduit 754 so that the production conduit and heater 760 may be removed from the wellbore.

[1082] Feedthrough 770 is used to pass lead-in cable 636 to supply power to heater 760. Lead-in cable 636 may be secured to conduit 754 with clamp 772. In some embodiments, lead-in cable 636 passes through packing material 532 using a separate feedthrough.

[1083] A lifting gas (for example, natural gas, methane, carbon dioxide, propane, and/or nitrogen) may be provided to the annulus between conduit 754 and casing 530. Valves 774 are located along a length of conduit 754 to allow gas to enter the production conduit and provide for gas lifting of fluids in the production conduit. The lifting gas may mix with fluids in conduit 754 to lower the density of the fluids and allow for gas lifting of the fluids out of the formation. In certain embodiments, valves 774 are located in or near the overburden section of the formation so that gas lifting is provided in the overburden section. In some embodiments, fluids are produced through the annulus between conduit 754 and casing 530 and the lifting gas is supplied through valves 774.

[1084] In an embodiment, fluids are produced using a pump coupled to conduit 754. The pump may be a submersible pump (for example, an electric or gas powered submersible pump). In some embodiments, a heater is coupled to conduit 754 to maintain the reduced viscosity of fluids in the conduit and/or the pump.

[1085] In certain embodiments, an additional conduit such as an additional coiled tubing conduit is placed in the formation. Sensors may be placed in the additional conduit. For example, a production logging tool may be placed in the additional conduit to identify locations of producing zones and/or to assess flow rates. In some embodiments, a temperature sensor (for example, a distributed temperature sensor, a fiber optic sensor, and/or an array of thermocouples) is placed in the additional conduit to determine a subsurface temperature profile.

[1086] Some embodiments of the heating/production assembly are used in a well that preexists (for example, the heating/production assembly is retrofitted for a preexisting production well, heater well, or monitoring well). An example of the heating/production assembly that may be used in the preexisting well is depicted in FIG. 141. Some preexisting wells include a pump. The pump in the preexisting well may be left in the heating/production well retrofitted with the heating/production assembly.

[1087] FIG. 141 depicts an embodiment of the heating/production assembly that may be located in the wellbore for gas lifting. In FIG. 141, conduit 754 is located in outside production conduit 776. In an embodiment, outside production conduit 776 is 11.4 cm diameter production tubing. Casing 530 has a diameter of 24.4 cm. Perforated casing 766 has a diameter of 11.4 cm. Seal assembly 768 seals conduit 754 inside outside production conduit 776. In an embodiment, pump 778 is a jet pump such as a bottomhole assembly jet pump.

[1088] FIG. 142 depicts another embodiment of a heating/production assembly that may be located in a wellbore for gas lifting. Heater 760 is located inside perforated casing 766. Heater 760 is coupled to lead-in cable 636 through a feedthrough in packing material 532. Production conduit 754 extends through packing material 532. Pump 778 is located along conduit 754. In certain embodiments, pump 778 is a jet pump or a bean pump. Valves 774 are located along conduit 754 for supplying lift gas to the conduit.

[1089] In some embodiments, heat is inhibited from transferring into conduit 754. FIG. 143 depicts an embodiment of conduit 754 and heaters 760 that inhibit heat transfer into the conduit. Heaters 760 are coupled to conduit 754. Heaters 760 include ferromagnetic sections 486 and non-ferromagnetic sections 488. Ferromagnetic sections 486 provide heat at a temperature that reduces the viscosity of fluids in or near a wellbore. Non-ferromagnetic sections 488 provide little or no heat. In certain embodiments, ferromagnetic sections 486 and non-ferromagnetic sections 488 are 6 m in length. In some embodiments, ferromagnetic sections 486 and non-ferromagnetic sections 488 are between 3 m and 12 m in length, between 4 m and 11 m in length, or between 5 m and 10 m in length. In certain embodiments, non-ferromagnetic sections 488 include perforations 780 to allow fluids to flow to conduit 754. In some embodiments, heater 760 is positioned so that perforations are not needed to allow fluids to flow to conduit 754.

[1090] Conduit 754 may have perforations 780 to allow fluid to enter the conduit. Perforations 780 coincide with non-ferromagnetic sections 488 of heater 760. Sections of conduit 754 that coincide with ferromagnetic sections 486 include insulation conduit 782. Conduit 782 may be a vacuum insulated tubular. For example, conduit 782 may be a vacuum insulated production tubular available from Oil Tech Services, Inc. (Houston, Texas, U.S.A.). Conduit 782 inhibits heat transfer into conduit 754 from ferromagnetic sections 486. Limiting the heat transfer into conduit 754 reduces heat loss and/or inhibits overheating of fluids in the conduit. In an embodiment, heater 760 provides heat along an entire length of the heater and conduit 754 includes conduit 782 along an entire length of the production conduit.

[1091] In certain embodiments, more than one wellbore 756 is used to produce heavy oils from a formation using the temperature limited heater. FIG. 144 depicts an end view of an embodiment with wellbores 756 located in hydrocarbon layer 460. Portions of wellbores 756 are placed substantially horizontally in a triangular pattern in hydrocarbon layer 460. In certain embodiments, wellbores 756 have a spacing of 30 m to 60 m, 35 m to 55 m, or 40 m to 50 m. Wellbores 756 may include production conduits and heaters previously described. Fluids may be heated and produced through wellbores 756 at an increased production rate above a cold production rate for the formation. Production may continue for a selected time (for example, 5 years to 10 years, 6 years to 9 years, or 7 years to 8 years) until heat produced from each of

wellbores 756 begins to overlap (superposition of heat begins). At such a time, heat from lower wellbores (such as wellbores 756 near the bottom of hydrocarbon layer 460) is continued, reduced, or turned off while production is continued. Production in upper wellbores (such as wellbores 756 near the top of hydrocarbon layer 460) may be stopped so that fluids in the hydrocarbon layer drain towards the lower wellbores. In some embodiments, power is increased to the upper wellbores and the temperature raised above the Curie temperature and/or the phase transformation temperature range to increase the heat injection rate. Draining fluids in the formation in such a process increases total hydrocarbon recovery from the formation.

[1092] In an embodiment, a temperature limited heater is used in a horizontal heater/production well. The temperature limited heater may provide selected amounts of heat to the "toe" and the "heel" of the horizontal portion of the well. More heat may be provided to the formation through the toe than through the heel, creating a "hot portion" at the toe and a "warm portion" at the heel. Formation fluids may be formed in the hot portion and produced through the warm portion, as shown in FIG. 145.

[1093] FIG. 145 depicts an embodiment of a heater well for selectively heating a formation. Heat source 202 is placed in opening 522 in hydrocarbon layer 460. In certain embodiments, opening 522 is a substantially horizontal opening in hydrocarbon layer 460. Perforated casing 766 is placed in opening 522. Perforated casing 766 provides support that inhibits hydrocarbon and/or other material in hydrocarbon layer 460 from collapsing into opening 522. Perforations in perforated casing 766 allow for fluid flow from hydrocarbon layer 460 into opening 522. Heat source 202 may include hot portion 784. Hot portion 784 is a portion of heat source 202 that operates at higher heat output than adjacent portions of the heat source. For example, hot portion 784 may output between 650 W/m and 1650 W/m, 650 W/m and 1500 W/m, or 800 W/m and 1500 W/m. Hot portion 784 may extend from a "heel" of the heat source to the "toe" of the heat source. The heel of the heat source is the portion of the heat source closest to the point at which the heat source enters a hydrocarbon layer. The toe of the heat source is the end of the heat source furthest from the entry of the heat source into the hydrocarbon layer.

[1094] In an embodiment, heat source 202 includes warm portion 786. Warm portion 786 is a portion of heat source 202 that operates at lower heat outputs than hot portion 784. For example, warm portion 786 may output between 30 W/m and 1000 W/m, 30 W/m and 750 W/m, or 100 W/m and 750 W/m. Warm portion 786 may be located closer to the heel of heat source 202. In certain embodiments, warm portion 786 is a transition portion (for example, a transition conductor) between hot portion 784 and overburden portion 788. Overburden portion 788 is located in overburden 458. Overburden portion 788 provides a lower heat output than warm portion 786. For example, overburden portion 788 may output between 10 W/m and 90 W/m, 15

W/m and 80 W/m, or 25 W/m and 75 W/m. In some embodiments, overburden portion 788 provides as close to no heat (0 W/m) as possible to overburden 458. Some heat, however, may be used to maintain fluids produced through opening 522 in a vapor phase or at elevated temperature in overburden 458.

[1095] In certain embodiments, hot portion 784 of heat source 202 heats hydrocarbons to high enough temperatures to result in coke 790 forming in hydrocarbon layer 460. Coke 790 may occur in an area surrounding opening 522. Warm portion 786 may be operated at lower heat outputs so that coke does not form at or near the warm portion of heat source 202. Coke 790 may extend radially from opening 522 as heat from heat source 202 transfers outward from the opening. At a certain distance, however, coke 790 no longer forms because temperatures in hydrocarbon layer 460 at the certain distance will not reach coking temperatures. The distance at which no coke forms is a function of heat output (W/m from heat source 202), type of formation, hydrocarbon content in the formation, and/or other conditions in the formation.

[1096] The formation of coke 790 inhibits fluid flow into opening 522 through the coking. Fluids in the formation may, however, be produced through opening 522 at the heel of heat source 202 (for example, at warm portion 786 of the heat source) where there is little or no coke formation. The lower temperatures at the heel of heat source 202 reduce the possibility of increased cracking of formation fluids produced through the heel. Fluids may flow in a horizontal direction through the formation more easily than in a vertical direction. Typically, horizontal permeability in a relatively permeable formation is approximately 5 to 10 times greater than vertical permeability. Thus, fluids flow along the length of heat source 202 in a substantially horizontal direction. Producing formation fluids through opening 522 is possible at earlier times than producing fluids through production wells in hydrocarbon layer 460. The earlier production times through opening 522 is possible because temperatures near the opening increase faster than temperatures further away due to conduction of heat from heat source 202 through hydrocarbon layer 460. Early production of formation fluids may be used to maintain lower pressures in hydrocarbon layer 460 during start-up heating of the formation. Start-up heating of the formation is the time of heating before production begins at production wells in the formation. Lower pressures in the formation may increase liquid production from the formation. In addition, producing formation fluids through opening 522 may reduce the number of production wells needed in the formation.

[1097] In some embodiments, a temperature limited heater positioned in a wellbore heats steam that is provided to the wellbore. The heated steam may be introduced into a portion of the formation. In certain embodiments, the heated steam may be used as a heat transfer fluid to heat a portion of the formation. In some embodiments, the steam is used to solution mine desired

minerals from the formation. In some embodiments, the temperature limited heater positioned in the wellbore heats liquid water that is introduced into a portion of the formation.

[1098] In an embodiment, the temperature limited heater includes ferromagnetic material with a selected Curie temperature and/or a selected phase transformation temperature range. The use of a temperature limited heater may inhibit a temperature of the heater from increasing beyond a maximum selected temperature (for example, at or about the Curie temperature and/or the phase transformation temperature range). Limiting the temperature of the heater may inhibit potential burnout of the heater. The maximum selected temperature may be a temperature selected to heat the steam to above or near 100% saturation conditions, superheated conditions, or supercritical conditions. Using a temperature limited heater to heat the steam may inhibit overheating of the steam in the wellbore. Steam introduced into a formation may be used for synthesis gas production, to heat the hydrocarbon containing formation, to carry chemicals into the formation, to extract chemicals or minerals from the formation, and/or to control heating of the formation.

[1099] A portion of the formation where steam is introduced or that is heated with steam may be at significant depths below the surface (for example, greater than about 1000 m, about 2500, or about 5000 m below the surface). If steam is heated at the surface of the formation and introduced to the formation through a wellbore, a quality of the heated steam provided to the wellbore at the surface may have to be relatively high to accommodate heat losses to the wellbore casing and/or the overburden as the steam travels down the wellbore. Heating the steam in the wellbore may allow the quality of the steam to be significantly improved before the steam is provided to the formation. A temperature limited heater positioned in a lower section of the overburden and/or adjacent to a target zone of the formation may be used to controllably heat steam to improve the quality of the steam injected into the formation and/or inhibit condensation along the length of the heater. In certain embodiments, the temperature limited heater improves the quality of the steam injected and/or inhibits condensation in the wellbore for long steam injection wellbores (especially for long horizontal steam injection wellbores).

[1100] A temperature limited heater positioned in a wellbore may be used to heat the steam to above or near 100% saturation conditions or superheated conditions. In some embodiments, a temperature limited heater may heat the steam so that the steam is above or near supercritical conditions. The static head of fluid above the temperature limited heater may facilitate producing 100% saturation, superheated, and/or supercritical conditions in the steam. Supercritical or near supercritical steam may be used to strip hydrocarbon material and/or other materials from the formation. In certain embodiments, steam introduced into the formation may have a high density (for example, a specific gravity of about 0.8 or above). Increasing the

density of the steam may improve the ability of the steam to strip hydrocarbon material and/or other materials from the formation.

[1101] In some embodiments, the tar sands formation may be treated by the in situ heat treatment process to produce pyrolyzed product from the formation. A significant amount of carbon in the form of coke may remain in tar sands formation when production of pyrolysis product from the formation is complete. In some embodiments, the coke in the formation may be utilized to produce heat and/or additional products from the heated coke containing portions of the formation.

[1102] In some embodiments, air, oxygen enriched air, and/or other oxidants may be introduced into the treatment area that has been pyrolyzed to react with the coke in the treatment area. The temperature of the treatment area may be sufficiently hot to support burning of the coke without additional energy input from heaters. The oxidation of the coke may significantly heat the portion of the formation. Some of the heat may transfer to portions of the formation adjacent to the treatment area. The transferred heat may mobilize fluids in portions of the formation adjacent to the treatment area. The mobilized fluids may flow into and be produced from production wells near the perimeter of the treatment area.

[1103] Gases produced from the formation heated by combusting coke in the formation may be at high temperature. The hot gases may be utilized in an energy recovery cycle (for example, a Kalina cycle or a Rankine cycle) to produce electricity.

[1104] The air, oxygen enriched air and/or other oxidants may be introduced into the formation for a sufficiently long period of time to heat a portion of the treatment area to a desired temperature sufficient to allow for the production of synthesis gas of a desired composition. The temperature may be from 500 °C to about 1000 °C or higher. When the temperature of the portion is at or near the desired temperature, a synthesis gas generating fluid, such as water, may be introduced into the formation to result in the formation of synthesis gas. Synthesis gas produced from the formation may be sent to a treatment facility and/or be sent through a pipeline to a desired location. During introduction of the synthesis gas generating fluid, the introduction of air, oxygen enriched air, and/or other oxidants may be stopped, reduced, or maintained. If the temperature of the formation reduces so that the synthesis gas produced from the formation does not have the desired composition, introduction of the syntheses gas generating fluid may be stopped or reduced, and the introduction of air, enriched air and/or other oxidants may be started or increased so that oxidation of coke in the formation reheats portions of the treatment area. The introduction of oxidant to heat the formation and the introduction of synthesis gas generating fluid to produce synthesis gas may be cycled until all or a significant portion of the treatment area is treated.

[1105] In some embodiments, temperature limited heaters are manufactured from austenitic stainless steels. These austenitic steels may include alloys with a face centered cubic (fcc) austenite phase being the primary phase. The fcc austenite phase may be stabilized by controlling the Fe-Cr-Ni and/or the $Fe_{18}Cr_8$-Ni concentration. Strength of the austenitic phase may be increased by incorporating other alloys in the fcc lattice. For low-temperature applications, the strength may be raised by adding alloying elements that increase the strength of the fcc lattice. This type of strengthening may be referred to as "solid solution strengthening". As the use temperature is increased, however, alloying elements in the austenite phase may react to form new phases such as $M_{23}C_6$, where M includes chromium and other elements that can form carbides. Other phases may form in austenite containing elements from Columns 4-13 of the Periodic Table. Examples of such elements include, but are not limited to, niobium, titanium, vanadium, tungsten, aluminum, or mixtures thereof. The size and distribution of various phases and their stability in the desired use temperature range determines the mechanical properties of the stainless steel. Nano-scale dispersions of precipitates such as carbides may produce the highest strength at high temperatures, but due to the size of the carbides, they may become unstable and coarsen. Alloys containing nano-scale precipitate dispersions may be unstable at temperatures of at least 750 °C. Since, heaters may heat a subsurface formation to temperatures at least 700 °C, heaters having improved strength alloys capable of.withstanding temperatures of at least 700 °C are desired.

[1106] In some embodiments, iron, chromium, and nickel alloys containing manganese, copper and tungsten, in combination with niobium, carbon and nitrogen, may maintain a finer grain size despite high temperature solution annealing or processing. Such behavior may be beneficial in reducing a heat-affected-zone in welded material. Higher solution-annealing temperatures are particularly important for achieving the best metal carbide (MC) nanocarbide. For example, niobium carbide nanocarbide strengthens during high-temperature creep service, and such effects are amplified (finer nanocarbide structures that are stable) by compositions of the improved alloys. Tubing and canister applications that include the composition of the improved alloys and are wrought processed result in stainless steels that may be able to age-harden during service at 700 °C to 800 °C. Improved alloys may be able to age-harden even more if the alloys are cold-strained prior to high-temperature service, but such cold-prestraining is not necessary for good high temperature properties or age-hardening. Some prior art alloys, such as NF709 require cold-prestraining to achieve good high temperature creep properties, and this is a disadvantage in particular because after such alloys are welded, the advantages of the cold-prestraining in the weld heat effected zone are lost. Other prior art alloys are adversely effected by cold-

prestraining with respect to high-temperature strength and long-term durability. Thus, cold prestraining may be limited or not permitted by, for example, construction codes.

[1107] In some embodiments of the new alloy compositions, the alloy may be cold worked by, for example, twenty percent, and the yield strength at 800 °C is not changed by more than twenty percent from yield strength at 800 °C of freshly annealed alloy.

[1108] The improved alloys described herein are suitable for low temperature applications, for example, cryogenic applications. The improved alloys which have strength and sufficient ductility at temperatures of, for example, -50 °C to -200 °C, also retain strength at higher temperatures than many alloys often used in cryogenic applications, such as 201LN and YUS130, thus for services such as liquefied natural gas, where a failure may result in a fire, the improved alloy would retain strength in the vicinity of the fire longer than other materials.

[1109] An improved alloy composition may include, by weight: about 18% to about 22% chromium, about 5% to about 13% nickel (and in some embodiments, from about 5% to about 9% by weight nickel), about 1% to about 10% copper (and in some embodiments, above 2% to about 6% copper), about 1% to about 10% manganese, about 0.3% to about 1% silicon, about 0.5% to about 1.5% niobium, about 0.5% to about 2% tungsten, and with the balance being essentially iron (for example, about 47.8% to about 68.12% iron). The composition may, in some embodiments, include other components, for example, about 0.3% to about 1% molybdenum, about 0.08% to about 0.2% carbon, about 0.2% to about 0.5% nitrogen or mixtures thereof. Other impurities or minor components typically present in steels may also be present. Such an improved alloy may be useful when processed by hot deformation, cold deformation, and/or welding into, for example, casings, canisters, or strength members for heaters. In some embodiments, the improved alloy includes, by weight: about 20% chromium, about 3% copper, about 4% manganese, about 0.3% molybdenum, about 0.77% niobium, about 13% nickel, about 0.5% silicon, about 1% tungsten, about 0.09% carbon, and about 0.26% nitrogen, with the balance being essentially iron. In certain embodiments, the improved alloy includes, by weight: about 19% chromium, about 4.2% manganese, about 0.3% molybdenum, about 0.8% niobium, about 12.5% nickel, about 0.5% silicon, about 0.09% carbon, about 0.24% nitrogen by weight with the balance being essentially iron. In certain embodiments, the improved alloy includes, by weight: about 21% chromium, about 3% copper, about 8% manganese, about 0.3% molybdenum, about 0.8% niobium, about 7% nickel, about 0.5% silicon, about 1% tungsten, about 0.13% carbon, and about 0.37% nitrogen, with the balance being essentially iron. In some embodiments, the improved alloy includes, by weight: about 20% chromium, about 4.4% copper, about 4.5 % manganese, about 0.3% molybdenum, about 0.8% niobium, about 7% nickel, about 0.5% silicon, about 1% tungsten, about 0.24% carbon, about 0.3% nitrogen by weight with the

balance being essentially iron. In some embodiments, improved alloys may vary an amount of manganese, amount of nickel, a W/Cu ratio, a Mo/W ratio, a C/N ratio, a Mn/N ratio, a Mn/Nb ratio, a Mn/Si ratio and/or a Mn/Ni ratio to enhance resistance to high temperature sulfidation, increase high temperature strength, and/or reduce cost. For example, for the improved wrought alloys to have a stable parent austenite phase, high strength from 600 °C to 900 °C, and stable nano carbide and nanocarbonitride microstructures, the improved wrought alloys may include combinations of alloying elements present in the improved wrought alloys such that the following ratios (using wt.%) are achieved: a) Mo/W – 0.3 to 0.5; b) W/Cu – 0.25 to 0.33; c) C/N – 0.25 to 0.33; d) Mn/Ni – 0.3 to 1.5; e) Mn/N – 20 to 25; f) Mn/Nb – 5 to 13; and g) Mn/Si – 4 to 20; and carbon plus nitrogen is from about 0.3 wt% to about 0.6 wt%.

[1110] Improved wrought alloy compositions may include the compositions described in the preceding paragraphs and compositions disclosed in U.S. Patent No. 7,153,373. The improved wrought alloy composition may include at least 3.25% by weight precipitates at about 800 °C. The improved wrought alloy composition may have been processed by aging or hot working and/or by cold working. As a result of such aging or hot working and/or cold working, the improved wrought alloy compositions (for example, NbC, Cr-rich $M_{23}C_6$) may contain nanocarbonitrides precipitates. Such nanocarbonitride precipitates are not known to be present in cast compositions such as those disclosed in U.S. Patent No. 7,153,373, and are believed to form upon hot working and/or cold working of the compositions. The nanocarbonitride precipitates may include particles having dimensions from about 5 nanometers to about 100 nanometers, from about 10 nanometers to about 90 nanometers, or from about 20 nanometers to about 80 nanometers. These wrought alloys may have microstructures that include, but are not limited to, nanocarbides (for example, NbC, Cr-rich $M_{23}C_6$), which form during aging (stress-free) or creep (stress < 0.5 yield stress (YS)). The nanocarbide precipitates may include particles having dimensions from 5 nanometers to 100 nanometers, from about 10 nanometers to about 90 nanometers, or from about 20 nanometers to about 80 nanometers. The microstructures may be a consequence of both the native alloy composition and the details of the wrought processing. In solution annealed material, the concentration of such nanoscale particles may be low. The nanoscale particles may be affected by solution anneal temperature/time (more and finer dispersion with longer anneal above 1150 °C) and by cold- or warm- prestrain (cold work) after the solution anneal treatment. Cold prestrain may create dislocation networks within the grains that may serve as nucleation sites for the nanocarbides. Solution annealed material initially has zero percent cold work. Bending, stretching, coiling, rolling or swaging may create, for example about 5 to about 15% cold work. The effect of the nanocarbides on yield strength or creep strength may be to provide strength based on dislocation-pinning, with more closely-spaced

pinning sites (higher concentration, finer dispersion) providing more strength (particles are barriers to climb or glide of dislocations).

[1111] The improved wrought alloy may include nanonitrides (for example, niobium chromium nitrides (NbCrN)) in the matrix together with nanocarbides, after, for example, being aged for 1000 hours at about 800 °C. The nanonitride precipitates may include particles having dimensions from about 5 nanometers to about 100 nanometers, from about 10 nanometers to about 90 nanometers, or from about 20 nanometers to about 80 nanometers. Niobium chromium nitrides have been identified using analytical electron microscopy as rich in niobium and chromium, and as the tetragonal nitride phase by electron diffraction (both carbides are cubic phases). X-ray energy dispersive quantitative analysis has shown that for the improved alloy compositions, these nanoscale nitride particles may have a composition by weight of: about 63% niobium, about 28% chromium, and about 6% iron, with other components being at most 5% each. Such niobium chromium nitrides were not observed in aged cast stainless steels with similar compositions, and appear to be a direct consequence of the wrought processing.

[1112] In some embodiments, the improved wrought alloy may include a mixture of microstructures (for example, a mixture of nanocarbides and nanonitrides). The mixture of microstructures may be responsible for the improved strength of these alloy compositions at elevated temperatures, such as, for example, about 900-1000 °C. In some embodiments, the improved alloys may have a yield strength greater than 35 kpsi, or 30 kpsi at about 800°C.

[1113] In some embodiments, the improved alloys are processed to produce a wrought material. Processing may include steps such as the following. A centrifugal cast pipe may be cast from the improved alloy. A section may be removed from the casting and heat treated at a temperature of at least 1250 °C for, for example, three hours. The heat treated section may be hot rolled at a temperature of at least 1200 °C to a thickness of about half of the original thickness inches), annealed at a temperature of at least 1200 °C for fifteen minutes, and then sandblasted. The sandblasted section may be cold rolled to a thickness of about one third of the original cast thickness. The cold rolled section may be annealed to a temperature of at least 1250 °C for a period of time, for example, an hour, in, for example, air with an argon cover, and then given a final additional heat treatment for one hour at a temperature of at least 1250 °C in air with an argon blanket. An alternative process may include any of the following: initially homogenizing the cast plate at a temperature of at least 1200 °C for a period of time, for example 1-1/2 hours; hot rolling at a temperature of at least 1200 °C to two thirds of the original cast thickness; and annealing the cold-rolled plate for one hour at a temperature of at least 1200 °C. The improved alloys may be extruded at, for example, about 1200 °C, with, for example, a mandrel diameter of

about 22.9 millimeters (0.9 inches) and a die diameter of about 34.3 millimeters (1.35 inches) to produce good quality tubes.

[1114] The wrought material may be welded by, for example, laser welding or tungsten gas arc welding. Thus, tubes may be produced by rolling plates and welding seams.

[1115] Annealing the improved alloys at higher temperatures, such as about 1250 °C, may improve properties of the alloys. At a higher temperature, more of the phases go into solution and upon cooling precipitate into phases that contribute positively to the properties, such as high temperature creep and tensile strength. Annealing at temperatures higher than 1250 °C, such as about 1300 °C may be beneficial. For example, the calculated phase present in the improved alloys may decrease by about 0.08% at about 1300 °C as opposed to the phase present in the improved alloys at about 1200 °C. Thus, upon cooling, more useful precipitates may form by about 0.08%. Improved alloys may have high temperature creep strengths and tensile strengths that are superior to conventional alloys. For example, niobium stabilized stainless steel alloys that include manganese, nitrogen, copper and tungsten may have high temperature creep strengths and tensile strengths that are improved, or substantially improved relative to conventional alloys such as 347H.

[1116] Improved alloys may have increased strength relative to standard stainless steel alloys such as Super 304H at high temperatures (for example, about 700 °C, about 800 °C, or above about 1000 °C). Superior high temperature creep-rupture strength (for example, creep-rupture strength at about 800 °C, about 900 °C, or about 1250 °C) may be improved as a result of (a) composition, (b) stable, fine-grain microstructures induced by high temperature processing, and (c) age-induced precipitation structures in the improved alloys. Precipitation structures include, for example, microcarbides that strengthen grain boundaries and stable nanocarbides that strengthen inside the grains. Presence of phases other than sigma, laves, G, and chi phases contribute to high temperature properties. Stable microstructures may be achieved by proper selection of components. High temperature aging induced or creep-induced microstructures may have minimal or no intermetallic sigma, laves and chi phases. Intermetallic sigma, laves and chi phases may weaken the strength properties of alloys and are therefore generally undesirable.

[1117] At about 800 °C, the improved alloys may include at least 3% or at least 3.25% by weight of microcarbides, other phases, and/or stable, fine grain microstructure that produce strength. At about 900 °C, the improved alloys may include, by weight, at least 1.5%, at least 2%, at least 3%, at least 3.5%, or at least 5% microcarbides, other phases, and/or stable, fine grain microstructure that produce strength. These values may be higher than the corresponding values in 347H or Super 304H stainless steel alloys at about 900 °C. At about 1250 °C improved alloys may include at least 0.5% by weight microcarbides, other phases, and/or stable, fine grain

microstructure that produce strength. The resulting higher weight percent of microcarbides, other phases, and/or stable, fine grain microstructure, and the exclusion of sigma and laves phases, may account for superior high temperature performance of the improved alloys.

[1118] Alloys having similar or superior high temperature performance to the improved alloys may be derived by modeling phase behavior at elevated temperatures and selecting compositions that retain at least 1.5%, at least 2%, or at least 2.5% by weight of phases other than sigma or laves phases at, for example, about 900 °C. For example, a stable microstructure may include an amount, by weight, of: niobium that is nearly ten times the amount of carbon, from 1% to 12% manganese, and from 0.15 to 0.5% of nitrogen. Copper and tungsten may be included in the composition to increase the amount of stable microstructures. The choice of elements for the improved alloys allows processing by various methods and results in a stable, fine grain size, even after heat treatments of at least 1250 °C. Many prior art alloys tend to grain coarsen significantly when annealed at such high temperatures whereas the improved alloy can be improved by such high temperature treatment. In some embodiments, grain size is controlled to achieve desirable high temperature tensile and creep properties. Stable grain structure in the improved alloys reduces grain boundary sliding, and may be a contributing factor for the better strength relative to commercially available alloys at temperatures above, for example, about 650 °C.

[1119] A downhole heater assembly may include 5, 10, 20, 40, or more heaters coupled together. For example, a heater assembly may include between 10 and 40 heaters. Heaters in a downhole heater assembly may be coupled in series. In some embodiments, heaters in a heater assembly may be spaced from about 8 meters (about 25 feet) to about 60 meters (about 195 feet) apart. For example, heaters in a heater assembly may be spaced about 15 meters (about 50 feet) apart. Spacing between heaters in a heater assembly may be a function of heat transfer from the heaters to the formation. Spacing between heaters may be chosen to limit temperature variation along a length of a heater assembly to acceptable limits. Heaters in a heater assembly may include, but are not limited to, electrical heaters, flameless distributed combustors, natural distributed combustors, and/or oxidizers. In some embodiments, heaters in a downhole heater assembly may include only oxidizers.

[1120] FIG. 146 depicts a schematic of an embodiment of downhole oxidizer assembly 800 including oxidizers 802 connected in series. In some embodiments, oxidizer assembly 800 may include oxidizers 802 and flameless distributed combustors. Oxidizer assembly 800 may be lowered into an opening in a formation and positioned as desired. In some embodiments, a portion of the opening in the formation may be substantially parallel to the surface of the Earth. In some embodiments, the opening of the formation may be otherwise angled with respect to the

surface of the Earth. In an embodiment, the opening may include a significant vertical portion and a portion otherwise angled with respect to the surface of the Earth. In certain embodiments, the opening may be a branched opening. Oxidizer assemblies may branch from common fuel and/or oxidant conduits in a central portion of the opening.

[1121] Oxidizing fluid 808 may be supplied to oxidizer assembly 800 through oxidant conduit 810. In some embodiments, fuel conduit 806 and/or oxidizers 802 may be positioned concentrically, or substantially concentrically, in oxidant conduit 810. In some embodiments, fuel conduit 806 and/or oxidizers 802 may be arranged other than concentrically with respect to oxidant conduit 810. In certain branched opening embodiments, fuel conduit 806 and/or oxidant conduit 810 may have a weld or coupling to allow placement of oxidizer assemblies 800 in branches of the opening. Exhaust gas 812 may pass through outer conduit 814 and out of the formation.

[1122] In some embodiments, the downhole oxidizer assembly includes a water conduit positioned in the oxidant conduit that is configured to deliver water to the fuel conduit prior to the first oxidizer in the oxidizer assembly. A portion of the water conduit may pass through a heated zone generated by the first oxidizer prior to a water entry point into the fuel conduit. In some embodiments, the fuel conduit is positioned adjacent to the oxidizers, and branches from the fuel conduit provide fuel to the other oxidizers. In some embodiments, the fuel conduit may comprise one or more orifices to selectively control the pressure loss along the fuel conduit.

[1123] Fuel 804 may be supplied to oxidizers 802 through fuel conduit 806. In some embodiments, the fuel for the oxidizers may be synthesis gas. In some embodiments, the fuel is synthesis gas (for example, a mixture of hydrogen and carbon monoxide) that was produced using an in situ heat treatment process. In some embodiments, the fuel contains products from a goal or heavy oil gasification process. The coal or heavy oil gasification process may take place above ground or below ground. After initiation of combustion of fuel and oxidant mixture in oxidizers 802, composition of the fuel may be varied to enhance operational stability of the oxidizers.

[1124] In certain embodiments, fuel used to initiate combustion may be enriched to decrease the temperature required for ignition or otherwise facilitate startup of oxidizers 802. In some embodiments, hydrogen or other hydrogen rich fluids may be used to enrich fuel initially supplied to the oxidizers. After ignition of the oxidizers, enrichment of the fuel may be stopped. In other embodiments, the fuel may comprise natural gas mixed with heavier components such as ethane, propane, butane, or carbon monoxide. In some embodiments, a portion or portions of fuel conduit 806 may include a catalytic surface (for example, a catalytic outer surface) to decrease an ignition temperature of fuel 804.

[1125] Coke formation may occur inside the fuel conduit if the fuel contains hydrocarbons components and the heat flux is sufficiently high. After oxidizer ignition, steps may be taken to reduce coking. For example, steam or water may be added to fuel conduit 806. In some embodiments, coking is inhibited by decreasing a residence time of fuel in fuel conduit 806. The residence time of fuel in fuel conduit 806 may decreased by varying the size of the fuel conduit. For example, one portion of fuel conduit 806 may be approximately 3/4 inch (approximately 1.9 cm) in diameter while another portion may be approximately 3/8 inch (approximately .95 cm) in diameter. Alternatively, the thickness and length of all or portions of fuel conduit 806 may be varied.

[1126] In some embodiments, coking is inhibited by insulating portions of fuel conduit 806 that pass through high temperature zones proximate oxidizers 802. For example, a portion of fuel conduit 806 may be coated with an insulating layer and/or a conductive layer. The insulating layer may be made from thermal insulating materials such as silicon carbide, alumina, mullite, zirconia, and other material known in the art. The conductive layer may be made from commercially available highly conductive materials such as ceramics and/or high temperature metals, including but not limited to Hexaloy (available from Arklay S. Richards Co., Inc.). The insulating layer and/or the conductive layer may be applied to fuel conduit 806 using a high velocity oxygen fuel or air plasma process. The resulting layer or layers may be heat treated.

[1127] In some embodiments, the fuel conduit is treated to remove coke formed in the fuel conduit by decoking. Decoking may be performed through mechanical means and/or chemical means. For example, coke may be removed from the fuel conduit by pumping a metal, studded, foam, or plastic pig through the fuel conduit. In an embodiment, a rod is inserted into fuel conduit 806 to dislodge coke particles and push them towards the last oxidizer in the oxidizer assembly. The rod may be a hydrolance or other high pressure pipe or tube used to direct high pressure water, air, nitrogen, and/or other gas to dislodge the coke.

[1128] FIG. 147 and FIG. 148 depict embodiments of oxidizers 802 of oxidizer assemblies positioned in outer conduits 814. Oxidizer 802 may be coupled to fuel conduit 806 that is positioned in oxidant conduit 810. Oxidant and fuel enter mix chamber 818 of oxidizer 802. A combustible mixture of fuel and oxidant passes from mix chamber 818 into the space between fuel conduit 806 and shield 824. Shield 824 surrounds a portion of fuel conduit 806. Shield 824 allow development of flame zone 2070 in oxidizer 802. Shield 824 inhibits gas flowing in oxidant conduit from extinguishing flame zone 2070 formed in oxidizer 802. Spacers may position oxidizer 802 in oxidant conduit 810. The spacers may be coupled to shield 824 and/or to oxidizer conduit 810. An igniter and/or combusting fuel in flame zone 2070 oxidizes the mixture of fuel and oxidant in the flame zone.

[1129] Insulating layer 2064 may be placed around fuel conduit 806 to at least partially surround a portion of the fuel conduit. Insulating layer 2064 may be made of a material with low thermal conductivity. Insulating layer 2064 may inhibit coking in fuel conduit 806. Insulating layer 2064 may only surround portions of fuel conduit 806 that pass through oxidizers 802. In some embodiments, the insulating layer covers the portion of the fuel conduit passing through the oxidizer and a portion of the fuel conduit before and/or after the oxidizer. In some embodiments, the entire fuel conduit is insulated.

[1130] Thermally conductive layer 2066 may surround or partially surround insulating layer 2064. Thermally conductive layer 2066 may be located adjacent to flame zone 2070. Thermally conductive layer 2066 may spread the heat of flame zone 2070 over a large area to help reduce the temperature applied to insulating layer 2064 below the flame zone. In some embodiments, the insulating layer does not include a thermally conductive layer.

[1131] FIG. 148 depicts a cross-sectional representation of an embodiment of oxidizer 802 with gas cooled sleeve 2068. A portion of sleeve 2068 may pass through oxidizer 802 to form an annular space. One or more spacers may be located between fuel conduit 806 and sleeve 2068 to position the sleeve relative to the fuel conduit. One or more feedthroughs 2072 may direct fuel from fuel conduit 806 to mix chamber 818 and/or to the area between shield 824 and the fuel conduit of oxidizer 802. Some gas flowing in oxidant conduit 810 passes between fuel conduit 806 and insulating sleeve 2064. Insulating sleeve 2064 may include thermally conductive layer 2066 to dissipate some of the heat from flame zone 2070 over a large area. Gas passing between fuel conduit 806 and insulating sleeve 2064 may inhibit excessive heating of the fuel conduit adjacent to flame zone 2070.

[1132] The flow of fuel in fuel conduit 806 is represented by arrow 2074, and the flow of gas (for example, air and exhaust products and unburned fuel from previous oxidizers) in oxidant conduit 810 is represented by arrow 2076. Exhaust gases from all of oxidizers in the oxidizer assembly pass through outer conduit 814 in the direction indicated by arrow 2078. Flow of gas between fuel conduit 806 and insulating sleeve 2064 may reduce the amount of heat transfer from the insulating sleeve to the fuel conduit. Flame zone 2070 may have a temperature of about 1100 °C (about 2000 °F) while the temperature in oxidant conduit adjacent to the shield of oxidizer 802 may be about 700 °C (about 1300 °F).

[1133] Oxidant may be supplied through the oxidant conduit to the oxidizers. Oxidizing fluid may include, but is not limited to, air, oxygen enriched air, and/or hydrogen peroxide. Depletion of oxygen in the oxidant may occur toward a terminal end of an oxidizer assembly. In some embodiments, the amount of excess oxidant supplied to the oxidizers is reduced to less than about 50% excess oxidant by weight by controlling the pressure, temperature, and flow rate of

the oxidant in the oxidant conduit. For example, after ignition, the amount of oxidant can be reduced when the temperature of the fuel conduit reaches about 650 °C (about 1200 °F). In some embodiments, the amount of excess oxidant is reduced to less than about 25% excess oxidant by weight. In other embodiments, the amount of excess oxidant is reduced to less than about 10% excess oxidant by weight.

[1134] In some embodiments, the amount of excess oxidant is reduced when the temperature downstream of the oxidizers becomes sufficiently hot to support reaction of oxidant and fuel outside of the oxidizers. Oxidant and fuel may react in regions between oxidizers. During such operation, the oxidizer assembly functions much like a flameless distributed combustor. Generating heat in the regions between the oxidizers may result in a smoother temperature profile along the length of the oxidizer assembly. The excess oxidant may be reduced such that the last oxidizer in the oxidizer assembly substantially eliminates the remaining oxidant in the oxidant conduit. The last oxidizer may be a catalytic oxidizer to minimize or eliminate oxidant remaining in the oxidant conduit.

[1135] When the temperature along the length of the oxidizer assembly increases to a temperature sufficient to support reaction of oxidant with fuel outside of the shields of the oxidizers, the mode of operation of the oxidizer assembly may shift from a series of individual oxidizers with aerodynamically staged flames to a more uniformly distributed or "reactor-stable" mode of operation. During the reactor-stable mode of operation, combustion may take place outside the shield along the entire length of the oxidant conduit. Under this condition stability is achieved by balancing overall heat loss and heat generation over the broad reaction zone. Local recirculation of hot combustion products to incoming reactants enables minimum reaction temperature where fuel-oxidant mixtures will oxidize without aerodynamic stabilization. In this mode of operation, the oxidizers may still serve as a "safety" or means of continuing stabilization, if the temperature falls below the temperature needed to sustain oxidation of the fuel and oxidant in one or more regions of the oxidizer. During reactor-stable mode of operation, the amount of excess oxygen supplied to the oxidizer assembly may be reduced. Having the ability to reduce the amount of excess oxygen supplied to the oxidizer assembly may significantly improve the overall economics of the system used to heat the formation.

[1136] A common problem associated with the operation of gas burners employing a flame mechanism is that at high temperatures, particularly above about 1500 °C (about 2730 °F), oxygen and nitrogen present in the air combine by a thermal formation mechanism to form pollutants such as NO and NO_2, commonly referred to as NOx. By controlling the flow of fuel and oxidant and by maintaining a distributed temperature, the formation of NOx may be inhibited. In some embodiments, the flow of fuel and oxidant is controlled to produce less than

about 10 parts per million by weight of NOx from the gas burner. The flow of oxidant may be controlled by having openings in shields of the oxidizers sized to bring a sufficient flow rate past to the flame zone to dilute the flame without causing the flame to be extinguished. Additionally, water added to the fuel conduit may inhibit NOx formation.

[1137] In some embodiments, initiation of the burner assembly is be accomplished by initializing combustion in a specified sequence beginning with the last oxidizer in the assembly. Referring to FIG. 146, oxidizer assembly 800 includes first oxidizer 2080, last oxidizer 2082, and second-to-last oxidizer 2084. In some embodiments, fuel is supplied through fuel conduit 806, and oxidant is supplied through oxidant conduit 810 to provide a first combustible mixture to last oxidizer 2082. Combustion is initiated in last oxidizer 2082 and the supply of oxidant is adjusted to supply second-to-last oxidizer 2084 with a second combustible mixture. Ignition of last oxidizer 2082 is maintained as second-to-last oxidizer 2084 is ignited. Thereafter this process of adjusting the supply of oxidant to provide a combustible fuel and oxidant mixture to the next unignited oxidizer and initiating combustion in the unignited oxidizer is repeated until first oxidizer 2080 is ignited. In some embodiments, the fuel pressure is greater than the oxidant pressure at an oxidizer before initiating combustion in the oxidizer.

[1138] In an embodiment, the start up sequence is optimized by controlling the oxidant and fuel pressure differential along the length of the oxidizer assembly. Because the pressure differential varies over the length of the burner assembly, a planned sequential ignition from oxidizer to oxidizer, starting with last (most remote) oxidizer 2082 may be achieved. In this embodiment, the fuel-oxidant mixture in the ignition region is optimized at last oxidizer 2082, then at the second to last oxidizer 2084, and so on, with the fuel-to-oxidant ratio being least optimal at first oxidizer 2080. The profiles may be controlled to change the sequence of ignition. In an embodiment, the profiles may be reversed so that first oxidizer 2080 is ignited first. Altering the profiles may comprise altering the pressure differential along the oxidizer assembly length by design of the fuel conduit diameter coupled with optimization of opening sizes that provide fuel to the oxidizers, of opening sizes that provide oxidant to the mix chambers of the oxidizers, and of openings in the shields that supply oxidant to the flame zone. In addition, control may be facilitated by flow restrictions positioned in fuel conduit 806.

[1139] FIG. 149 depicts a perspective view of an embodiment of oxidizer 802 of the downhole oxidizer assembly. Oxidizer 802 may include mix chamber 818, igniter holder 820, nozzle and flame holder 822, and shield 824. Fuel conduit 806 may pass through oxidizer 802. Fuel conduit 806 may have one or more fuel openings 826 within mix chamber 818 (as shown in FIG. 147). In some embodiments, additional openings in fuel conduit 806 allow additional fuel to pass into the space between the fuel conduit and shield 824. Openings 828 allow oxidant to flow into mix

chamber 818. Opening 830 allows a portion of the igniter supported on igniter holder 820 to pass into oxidizer 802. Shield 824 may include openings 832. Openings 832 may provide additional oxidant to a flame in shield 824. Openings 832 may stabilize the flame in oxidizer 802 and moderate the temperature of the flame. Spacers 834 may be positioned on shield 824 to keep oxidizer 802 positioned in oxidant conduit 810.

[1140] In some embodiments, flame stabilizers may be added to the oxidizers. The flame stabilizers may attach the flame to the shield. The high bypass flow around the oxidizer cools the shield and protects the internals of the oxidizer from damage enabling long term operation. FIGS. 150-155 depict various embodiments of shields 824 with flame stabilizers 836. Flame stabilizer 836 depicted in FIG. 150 is a ring substantially perpendicular to shield 824. The ring shown in FIG. 151 is angled away from openings 832. The rings may amount to up to about 25% annular area blockage. The rings may establish a recirculation zone near shield 824 and away from the fuel conduit passing through the center of the shield.

[1141] FIG. 152 depicts an embodiment of flame stabilizer 836 in shield 824. Flame stabilizer 836 is positioned at an angle over the openings. Flame stabilizer 836 may divert incoming fluid flow through openings 832 in an upstream direction. The diverted incoming fluid may set up a flow condition somewhat analogous to high swirl recirculation (reverse flow). One or more stagnation zones may develop where a flame front is stable.

[1142] FIG. 153 depicts an embodiment of multiple flame stabilizers 836 in shield 824. Shield 824 may have two or more sets of openings 832 along an axial length of the shield. Rings may be positioned behind one or more of the sets of openings 832. In some embodiments, adjacent rings may cause too much gas flow interference. To inhibit gas flow interference, 3 partial rings (each ring being about 1/6 the circumference) may be evenly spaced about the circumference instead of one complete ring. The next set of 3 partial rings along the axial length of heat shield may be staggered (for example, the partial rings may be rotated by 120° relative to the first set of 3 partial rings). FIG. 154 depicts a cross-sectional representation of shield 824 showing the last set of openings 832 and the last set of flame stabilizers 836. Shield 824 includes spacers 834. In other embodiments, fewer or more than 3 partial rings may be used (for example, two partial rings may be used for the first set of openings, and four partial rings may be used for the next set of openings). Flame stabilizers 836 may be perpendicular to shield 824, angled towards openings 832, angled away from the openings (as depicted in FIG. 153) or positioned as combinations of perpendicular and angled orientations.

[1143] FIG. 155 depicts an embodiment wherein flame stabilizers 836 are deflector plates or baffles extending over all or portions of openings 832. The portions of flame stabilizers 836 positioned over the openings may be cylindrical sections with the concave portions facing

openings 832. Flame stabilizers 836 may divert incoming fluid flow and allow the flame root area to develop around the deflectors. Some openings in the shield may not include flame stabilizers.

[1144] In some embodiments, deflectors may be positioned on the outer surface of the shield near to openings in the shield. The deflectors may direct some of the gas flowing through the oxidant conduit through the openings in the shield.

[1145] As depicted in FIGS 149-155, shield 824 may include opening 832. The size and/or number of openings 832 may be varied depending on position of the oxidizer in the oxidizer assembly to moderate the temperature and ensure fuel combustion. In some embodiments, the geometry and size of openings 832 on a single oxidizer may be varied to compensate for changing conditions and needs along the length of the oxidizer.

[1146] FIGS 156-158 depict perspective views of various sectioned oxidizer embodiments. Oxidizers 802 include oxidant openings 828, mix chambers 818, nozzle and flame holder 822, and shield 824. FIGS 156-158 depict various positions and sizes for openings 832 in shield 824oxidant.

[1147] In some embodiments, one or more of the openings in the shield may be angled in a non-perpendicular direction relative to the longitudinal axis of the shield. Angled openings act as nozzles to alter the entry path of gas into the shield. Angled openings may promote formation of internal low velocity recirculation zones where the reaction front can stabilize and improve the stability and reliability of the oxidizer.

[1148] The use of flame stabilizers, various sizes of openings in the shield and/or angled openings may establish the flame zone of the oxidizer close to the shield and as far away from the fuel conduit to maximize radial separation of the flame zone from the fuel conduit to minimize direct heating of the fuel conduit by the flame zone. The use of flame stabilizers, various sizes of openings in the shield and/or angled openings may Directional configurations may also achieve lower NOx emissions by effectively aerodynamically staging the combustion zone and creating fuel rich and lean zones. In fuel rich zones N_2 formation (instead of NOx) will be favored and aerodynamic staging will control peak temperatures and thermal NOx formation. Such configurations can also enable control of the peak longitudinal temperature profile and flame radiation, hence suppressing overheating of the fuel conduit.

[1149] In one embodiment, the oxidizers may comprise heat shields, which utilize a louvered design to direct flow into the shield. FIG. 159 depicts oxidizer 802 with louvered openings 832 in shield 824. Louvered openings 832 are in communication with the oxidant conduit and are configured to direct flow into shield 824 in a direction opposite to the direction of flow in the oxidant conduit. FIG. 160 depicts a cross-sectional representation of a portion of shield 824 with

louvered opening 832. Gas with oxidant may be directed from oxidant conduit to the inside of shield 824. Arrow 2086 indicates the direction of gas flow from the oxidant conduit to the inside of shield. Arrow 2088 indicates the direction of gas flow in the oxidant conduit.

[1150] In some embodiments, fuel passes through a heated region before being supplied to the first oxidizer (oxidizer 2080 in FIG. 146). Passing the fuel through the heated region may preheat the fuel and ensure that the fuel and additives in the fuel (for example, water to inhibit coking) are in the gas phase. Ensuring gas phase fuel may avoid plugging in first oxidizer 2080. FIG. 161 depicts an embodiment of first oxidizer 2080 and fuel conduit 806. Fuel conduit 806 may include sleeve 2090. Fuel may flow through sleeve, and a portion of the fuel may flow in the opposite direction in the annular space between the sleeve and fuel conduit 806. A portion of the fuel flowing in the annular space between sleeve 2090 and fuel conduit 806 passes through openings 826 into mix chamber 818.

[1151] In some embodiments, a portion of the fuel flowing in the annular space between sleeve 2090 and fuel conduit 806 passes through openings 826 into the annular space between the fuel conduit and shield 824. Supplying fuel into this annular space may allow flame zone 2070 to extend through a significant portion of first oxidizer 2080 so that the first oxidizer is able to input more heat into the formation. First oxidizer 2080 may be configured to input more heat into the formation to help compensate for heat losses attributable to the oxidizer being the first oxidizer of the oxidizer assembly. Having first oxidizer configured to input more heat into the formation than other oxidizers of the oxidizer assembly may allow for a decrease in the total number of oxidizers needed in the downhole assembly.

[1152] One or more of the oxidizers in an oxidizer assembly may be a catalytic burner. The catalytic burners may include a catalytic portion (for example, catalyst chamber) followed by a homogenous portion (for example, mix chamber). Catalytic burners may be started late in an ignition sequence, and may ignite without igniters. Oxidant for the catalytic burners may be sufficiently hot from upstream burners (for example, the oxidant may be at a temperature of about 370 °F (about 700 °C) if the fuel is primarily methane) so that a primary mixture would react over the catalyst in the catalyst portion and produce enough heat so that exiting products ignite a secondary mixture in the homogenous portion of the oxidizer. In some embodiments, the fuel may include enough hydrogen to allow the needed temperature of the oxidant to be lower. Catalysts used for this purpose may include palladium, platinum, platinum/iridium, and platinum/rhodium.

[1153] FIG. 162 depicts a cross-sectional representation of catalytic burner 838. Oxidizer may enter mix chamber 818 through openings 828. Fuel may enter mix chamber 818 from fuel conduit 806 through fuel openings 826'. Fuel and oxidizer may flow to catalyst chamber 840.

Catalyst chamber 840 contains catalyst which reacts a mixture from mix chamber 818 to produce reaction products at a temperature that is sufficient to ignite fuel and oxidant. In some embodiments, the catalyst includes palladium on a honeycomb ceramic support. The fuel and oxidant react in catalyst chamber 840 to form hot reaction products. The hot reaction products may be directed to the annular space between shield 824 and fuel conduit 806. Additional fuel enters the annular space through openings 826" in fuel conduit 806. Additional oxidant enters the annular space through openings 832. The hot reaction products generated by catalyst 840 may ignite fuel and oxidant in autoignition zone 842. Autoignition zone 842 may allow fuel and oxidant to form flame zone 2070. In some embodiments, the catalytic burner includes flame stabilizers or other types of gas flow modifiers.

[1154] In some embodiments a catalytic burner may include an igniter to simplify startup procedures. FIG. 163 depicts catalytic burner 838 that includes igniter 816. Igniter 816 is positioned in mix chamber 818. Catalyst burner 838 includes catalyst chamber 840. Catalyst chamber contains a catalyst that reacts a mixture from mix chamber 818 to produce reaction products at a temperature that is sufficient to ignite fuel and oxidant. Oxidant enters mix chamber through openings 828A. Fuel enters the mix chamber from fuel line through fuel openings 826A. The fuel input into mixture chamber 818 may be only a small fraction of the fuel input for catalytic burner 838. Igniter 816 raises the temperature of the fuel and oxidant to combustion temperatures in pre-heat zone 846. Flame stabilizer 836 may be positioned in mixing chamber 818. Heat from pre-heat zone 846 and/or combustion products may heat additional fuel that enters mixing chamber 818 through fuel openings 826B and additional oxidant that enters the mixing chamber through openings 828B. Openings 826B and openings 828B may be upstream of flame stabilizer 836. The additional fuel and oxidant are heated to a temperature sufficient to support reaction on catalyst 840.

[1155] Heated fuel and oxidant from mixing chamber 818 pass to catalyst 840. The fuel and oxidant react on catalyst 840 to form hot reaction products. The hot reaction products may be directed to heat shield 824. Additional fuel enters heat shield 824 through openings 826C in fuel conduit 806. Additional oxidant enters heat shield 824 through openings 832. The hot reaction products generated by catalyst 840 may ignite fuel and oxidant in autoignition zone 842. Autoignition zone 842 may allow fuel and oxidant to form main combustion zone 2070. In some embodiments, the catalytic burner includes flame stabilizers or other types of gas flow modifiers.

[1156] In some embodiments, all of the oxidizers in the oxidizer assembly are catalytic burners. In some embodiments, the first or the first several oxidizers in the oxidizer assembly are catalytic burners. The oxidant supplied to these burners may be at a lower temperature than subsequent burners. Using catalytic burners with igniters may stabilize the first performance of the first

several oxidizers in the oxidizer assembly. Catalytic burners may be used in-line with other burners to reduce emissions by allowing lower flame temperatures while still having substantially complete combustion.

[1157] In some embodiments, a catalytic converter may be positioned at the end of the oxidizer assembly or in the exhaust gas return. The catalytic converter may remove unburned hydrocarbons and/or remaining NOx compounds or other pollutants. The catalytic converter may benefit from the relatively high temperature of the exhaust gas. In some embodiments, catalytic burners in series may be integrated with coupled catalytic converters to limit undesired emissions from the oxidizer assembly. In some embodiments, a selectively permeable material may be used to allow carbon dioxide or other fluids to be separated from the exhaust gas.

[1158] In one embodiment, initiation of the burner assembly may be accomplished by initializing combustion with hydrogen and later switching to natural gas or another fuel. The use of hydrogen-enriched fuel may suppress flame radiation and reduce heating of the fuel conduit. Oxidizers of the oxidizer assembly may be ignited using hydrogen or fuel that is highly enriched with hydrogen. Once ignited, the composition of fuel may be adjusted to comprise natural gas and/or other fuels. The initial use of hydrogen or hydrogen-enriched fuel widens the flammability envelope enabling much easier startup. An initial fuel composition could then be "chased" with production gas or other more economical gases. Alternatively, the entire system could burn hydrogen. With no carbon in the fuel, there would be no need for additional decoking methods.

[1159] In some embodiments, pulverized coal is the fuel used to heat the subsurface formation. The pulverized coal may be carried into the wellbores with a non-oxidizing fluid (for example, carbon dioxide and/or nitrogen). An oxidant may be mixed with the pulverized coal at several locations in the wellbore. The oxidant may be air, oxygen enriched air and/or other types of oxidizing fluids. Igniters located at or near the mixing locations initiate oxidation of the coal and oxidant. The igniters may be catalytic igniters, glow plugs; spark plugs, and/or electrical heaters (for example, an insulated conductor temperature limited heater with heating sections located at mixing locations of pulverized coal and oxidant) that are able to initiate oxidation of the oxidant with the pulverized coal. In FIG. 146, pulverized coal entrained in a carrier fluid may be fuel 804 supplied to oxidizers 802 through fuel conduit 806. Initially, oxidizer assembly 800 may be started using hydrogen, natural gas, or other fuel. After temperatures of oxidizers 802 are hot enough to support rapid pulverized coal oxidation (for example, the temperature in and adjacent to the oxidizers is above about 600 °C), the fuel may be changed to pulverized coal and carrier gas.

[1160] The particles of the pulverized coal may be small enough to pass through flow orifices and achieve rapid combustion in the oxidant. The pulverized coal may have a particle size distribution from about 1 micron to about 300 microns, from about 5 microns to about 150 microns, or from about 10 microns to about 100 microns. Other pulverized coal particle size distributions may also be used. At 600 °C, the time to burn the volatiles in pulverized coal with a particle size distribution from about 10 microns to about 100 microns may be about one second.

[1161] When using coal as the fuel for downhole oxidizers, exhaust gases from the heater wells may be treated to remove unreacted coal, ash, fines and/or other particles in the exhaust gas. In some embodiments, the exhaust gas passes through one or more cyclones to remove particles from the exhaust gas. The exhaust gas may be further processed to remove selected compounds (for example, sulfur and/or nitrogen compounds), may be used as a drive fluid for mobilizing hydrocarbons in a formation, may be sequestered in a subsurface formation, and/or may be otherwise handled.

[1162] In other embodiments, other types of downhole oxidizers are used for the subsurface oxidation of coal to heat selected portions of the formation. FIG. 164 depicts a schematic representation of heater 2092 that uses pulverized coal as fuel. Heater 2092 may include outer conduit 814, first conduit 2094, and second conduit 2096. First conduit 2094 is positioned in outer conduit 814, and second conduit 2096 is positioned in the first conduit. The end of second conduit may be closed. Second conduit 2096 may include critical flow orifices 2098. The flow rate and/or pressures of the fluids flowing through first conduit 2094 and second conduit 2096 may be controlled to allow for mixing of fluid from the first conduit with fluid from the second conduit at desired locations in the first conduit.

[1163] In an embodiment, coal and carrier gas is introduced into heater 2092 through first conduit 2094, and oxidant is introduced through second conduit 2096. The flow rate and/or pressure in first conduit 2094 and second conduit 2096 are controlled so that the oxidant flows through critical flow orifices 2098 into the coal and carrier gas flowing through first conduit 2094. Reaction of the coal and oxidant occurs in first conduit 2094. Exhaust gases pass through outer conduit 814 to the surface. Passing the exhaust gases past the locations where oxidant and coal are oxidized may reduce temperature variations along the length of the heated section of heater 2092.

[1164] In an embodiment, oxidant is introduced into heater 2092 through first conduit 2094, and coal and carrier gas is introduced through second conduit 2096. The flow rate and/or pressure of in first conduit 2094 and second conduit 2096 are controlled so that the coal and carrier gas flows through critical flow orifices 2098 into the oxidant flowing through first conduit 2094. Reaction

of the coal and oxidant occurs in first conduit 2094. Exhaust gases pass through outer conduit 814 to the surface.

[1165] FIG. 165 depicts a schematic representation of heater 2092 that uses pulverized coal as fuel. Heater 2092 may include outer conduit 814, first conduit 2094, and second conduit 2096. First conduit 2094 is positioned in outer conduit 814, and second conduit 2096 is positioned in the first conduit. The end of first conduit 2094 may be sealed closed against second conduit 2096. Second conduit 2096 may include critical flow orifices 2098. The flow rate and/or pressures of the fluids flowing through first conduit 2094 and second conduit 2096 may be controlled to allow for mixing of fluid from the first conduit with fluid from the second conduit at desired locations in the second conduit.

[1166] In an embodiment, oxidant is introduced into heater 2092 through first conduit 2094, and coal and carrier gas is introduced through second conduit 2096. The flow rate and/or pressure of in first conduit 2094 and second conduit 2096 are controlled so that the oxidant flows through critical flow orifices 2098 into the coal and carrier gas flowing through second conduit 2096. Reaction of the coal and oxidant occurs in second conduit 2096. Reacting coal and oxidant in second conduit 2096 and passing exhaust gases pass through outer conduit 814 to the surface may reduce the formation of hot zones adjacent to sections of heater 2092 where oxidation occurs.

[1167] In an embodiment, coal and carrier gas is introduced into heater 2092 through first conduit 2094, and oxidant is introduced through second conduit 2096. The flow rate and/or pressure in first conduit 2094 and second conduit 2096 are controlled so that the coal and carrier gas flows through critical flow orifices 2098 into oxidant flowing through second conduit 2096. Reaction of the coal and oxidant occurs in second conduit 2096. Exhaust gases pass through outer conduit 814 to the surface.

[1168] In some in situ heat treatment process embodiments, a circulation system is used to heat the formation. The circulation system may be a closed loop circulation system. FIG. 166 depicts a schematic representation of a system for heating a formation using a circulation system. The system may be used to heat hydrocarbons that are relatively deep in the ground and that are in formations that are relatively large in extent. In some embodiments, the hydrocarbons may be 100 m, 200 m, 300 m or more below the surface. The circulation system may also be used to heat hydrocarbons that are not as deep in the ground. The hydrocarbons may be in formations that extend lengthwise up to 500 m, 750 m, 1000 m, or more. The circulation system may become economically viable in formations where the length of the hydrocarbon containing formation to be treated is long compared to the thickness of the overburden. The ratio of the hydrocarbon formation extent to be heated by heaters to the overburden thickness may be at least

3, at least 5, or at least 10. The heaters of the circulation system may be positioned relative to adjacent heaters so that superposition of heat between heaters of the circulation system allows the temperature of the formation to be raised at least above the boiling point of aqueous formation fluid in the formation.

[1169] In some embodiments, heaters 760 may be formed in the formation by drilling a first wellbore and then drilling a second wellbore that connects with the first wellbore. Piping may be positioned in the U-shaped wellbore to form U-shaped heater 760. Heaters 760 are connected to heat transfer fluid circulation system 868 by piping. Gas at high pressure may be used as the heat transfer fluid in the closed loop circulation system. In some embodiments, the heat transfer fluid is carbon dioxide. Carbon dioxide is chemically stable at the required temperatures and pressures and has a relatively high molecular weight that results in a high volumetric heat capacity. Other fluids such as steam, air, helium and/or nitrogen may also be used. The pressure of the heat transfer fluid entering the formation may be 3000 kPa or higher. The use of high pressure heat transfer fluid allows the heat transfer fluid to have a greater density, and therefore a greater capacity to transfer heat. Also, the pressure drop across the heaters is less for a system where the heat transfer fluid enters the heaters at a first pressure for a given mass flow rate than when the heat transfer fluid enters the heaters at a second pressure at the same mass flow rate when the first pressure is greater than the second pressure. In some embodiments, a liquid heat transfer fluid may be used. The liquid heat transfer fluid may be a natural or synthetic oil, or other type of high temperature heat transfer fluid.

[1170] Heat transfer fluid circulation system 868 may include heat supply 870, first heat exchanger 872, second heat exchanger 874, and compressor 876. Heat supply 870 heats the heat transfer fluid to a high temperature. Heat supply 870 may be a furnace, solar collector, chemical reactor, nuclear reactor, fuel cell exhaust heat, or other high temperature source able to supply heat to the heat transfer fluid. In the embodiment depicted in FIG. 166, heat supply 870 is a furnace that heats the heat transfer fluid to a temperature in a range from about 700 °C to about 920 °C, from about 770 °C to about 870 °C, or from about 800 °C to about 850 °C. In an embodiment, heat supply 870 heats the heat transfer fluid to a temperature of about 820 °C. The heat transfer fluid flows from heat supply 870 to heaters 760. Heat transfers from heaters 760 to formation 758 adjacent to the heaters. The temperature of the heat transfer fluid exiting formation 758 may be in a range from about 350 °C to about 580 °C, from about 400 °C to about 530 °C, or from about 450 °C to about 500 °C. In an embodiment, the temperature of the heat transfer fluid exiting formation 758 is about 480 °C. The metallurgy of the piping used to form heat transfer fluid circulation system 868 may be varied to significantly reduce costs of the piping. High temperature steel may be used from heat supply 870 to a point where the

temperature is sufficiently low so that less expensive steel can be used from that point to first heat exchanger 872. Several different steel grades may be used to form the piping of heat transfer fluid circulation system 868.

[1171] Heat transfer fluid from heat supply 870 of heat transfer fluid circulation system 868 passes through overburden 458 of formation 758 to hydrocarbon layer 460. Portions of heaters 760 extending through overburden 458 may be insulated. In some embodiments, the insulation or part of the insulation is a polyimide insulating material. Inlet portions of heaters 760 in hydrocarbon layer 460 may have tapering insulation to reduce overheating of the hydrocarbon layer near the inlet of the heater into the hydrocarbon layer.

[1172] In some embodiments, the diameter of the pipe in overburden 458 may be smaller than the diameter of pipe through hydrocarbon layer 460. The smaller diameter pipe through overburden 458 may allow for less heat transfer to the overburden. Reducing the amount of heat transfer to overburden 458 reduces the amount of cooling of the heat transfer fluid supplied to pipe adjacent to hydrocarbon layer 460. The increased heat transfer in the smaller diameter pipe due to increased velocity of heat transfer fluid through the small diameter pipe is offset by the smaller surface area of the smaller diameter pipe and the decrease in residence time of the heat transfer fluid in the smaller diameter pipe.

[1173] After exiting formation 758, the heat transfer fluid passes through first heat exchanger 872 and second heat exchanger 874 to compressor 876. First heat exchanger 872 transfers heat between heat transfer fluid exiting formation 758 and heat transfer fluid exiting compressor 876 to raise the temperature of the heat transfer fluid that enters heat supply 870 and reduce the temperature of the fluid exiting formation 758. Second heat exchanger 874 further reduces the temperature of the heat transfer fluid before the heat transfer fluid enters compressor 876.

[1174] FIG. 167 depicts a plan view of an embodiment of wellbore openings in the formation that is to be heated using the circulation system. Heat transfer fluid entries 878 into formation 758 alternate with heat transfer fluid exits 880. Alternating heat transfer fluid entries 878 with heat transfer fluid exits 880 may allow for more uniform heating of the hydrocarbons in formation 758.

[1175] In some embodiments, piping for the circulation system may allow the direction of heat transfer fluid flow through the formation to be changed. Changing the direction of heat transfer fluid flow through the formation allows each end of a u-shaped wellbore to initially receive the heat transfer fluid at the heat transfer fluid's hottest temperature for a period of time, which may result in more uniform heating of the formation. The direction of heat transfer fluid may be changed at desired time intervals. The desired time interval may be about a year, about six months, about three months, about two months or any other desired time interval.

[1176] In some embodiments, nuclear energy may be used to heat the heat transfer fluid used in the circulation system to heat a portion of the formation. Heat supply 870 in FIG. 166 may be a pebble bed reactor or other type of nuclear reactor, such as a light water reactor. The use of nuclear energy provides a heat source with no carbon dioxide emissions. Also, the use of nuclear energy can be more efficient because energy losses resulting from the conversion of heat to electricity and electricity to heat are avoided by directly utilizing the heat produced from the nuclear reactions without producing electricity.

[1177] In some embodiments, a nuclear reactor may heat helium. For example, helium flows through a pebble bed reactor, and heat transfers to the helium. The helium may be used as the heat transfer fluid to heat the formation. In some embodiments, the nuclear reactor may heat helium, and the helium may be passed through a heat exchanger to provide heat to the heat transfer fluid used to heat the formation. The pebble bed reactor may include a pressure vessel that contains encapsulated enriched uranium dioxide fuel. Helium may be used as a heat transfer fluid to remove heat from the pebble bed reactor. Heat may be transferred in a heat exchanger from the helium to the heat transfer fluid used in the circulation system. The heat transfer fluid used in the circulation system may be carbon dioxide, a molten salt, or other fluid. Pebble bed reactor systems are available from PBMR Ltd (Centurion, South Africa).

[1178] FIG. 168 depicts a schematic diagram of a system that uses nuclear energy to heat treatment area 882. The system may include helium system gas blower 884, nuclear reactor 886, heat exchanger units 888, and heat transfer fluid blower 890. Helium system gas blower 884 may draw heated helium from nuclear reactor 886 to heat exchanger units 888. Helium from heat exchanger units 888 may pass through helium system gas blower 884 to nuclear reactor 886. Helium from nuclear reactor 886 may be at a temperature of about 900 °C to about 1000 °C. Helium from helium gas blower 884 may be at a temperature of about 500 °C to about 600 °C. Heat transfer fluid blower 890 may draw heat transfer fluid from heat exchanger units 888 through treatment area 882. Heat transfer fluid may pass through heat transfer fluid blower 890 to heat exchanger units 888. The heat transfer fluid may be carbon dioxide. The heat transfer fluid may be at a temperature from about 850 °C to about 950 °C after exiting heat exchanger units 888.

[1179] In some embodiments, the system may include auxiliary power unit 900. In some embodiments, auxiliary power unit 900 generates power by passing the helium from heat exchanger units 888 through a generator to make electricity. The helium may be sent to one or more compressors and/or heat exchangers to adjust the pressure and temperature of the helium before the helium is sent to nuclear reactor 886. In some embodiments, auxiliary power unit 900 generates power using a heat transfer fluid (for example, ammonia or aqua ammonia). Helium

from heat exchanger units 888 is sent to additional heat exchanger units to transfer heat to the heat transfer fluid. The heat transfer fluid is taken through a power cycle (such as a Kalina cycle) to generate electricity. In an embodiment, nuclear reactor 886 is a 400 MW reactor and auxiliary power unit 900 generates about 30 MW of electricity.

[1180] FIG. 169 depicts a schematic elevational view of an arrangement for an in situ heat treatment process. U-shaped wellbores may be formed in the formation to define treatment areas 882A, 882B, 882C, 882D. Additional treatment areas could be formed to the sides of the shown treatment areas. Treatment areas 882A, 882B, 882C, 882D may have widths of over 300 m, 500 m, 1000 m, or 1500 m. Well exits and entrances for the wellbores may be formed in well openings area 902. Rail lines 904 may be formed along sides of treatment areas 882. Warehouses, administration offices and/or spent fuel storage facilities may be located near ends of rail lines 904. Facilities 906 may be formed at intervals along spurs of rail lines 904. Each facility 906 may include a nuclear reactor, compressors, heat exchanger units and other equipment needed for circulating hot heat transfer fluid to the wellbores. Facilities 906 may also include surface facilities for treating formation fluid produced from the formation. In some embodiments, heat transfer fluid produced in facility 906' may be reheated by the reactor in facility 906" after passing through treatment area 882A. In some embodiments, each facility 906 is used to provide hot treatment fluid to wells in one half of the treatment area 882 adjacent to the facility. Facilities 906 may be moved by rail to another facility site after production from a treatment area is completed.

[1181] In some embodiments, nuclear energy may be used to directly heat a portion of the subsurface formation. The portion of the subsurface formation may be part of the hydrocarbon treatment area. As opposed to using a nuclear reactor facility to heat a heat transfer fluid, which is then provided to the subsurface formation to heat the subsurface formation, one or more self-limiting nuclear heaters may be positioned underground to directly heat the subsurface formation.

[1182] In some embodiments, a nuclear heater assembly may include one or more encapsulated nuclear material elements (nuclear pebble heaters) positioned in the subsurface formation. In some embodiments, the encapsulated nuclear material elements are commercially available spheres that include fissionable material encapsulated in carbon. The nuclear pebble heaters are typically used in pebble bed reactors. Nuclear pebble heaters may be positioned in a fuel conduit within the subsurface formation. Nuclear pebble heaters may be positioned in the fuel conduit before and/or after the fuel conduit is positioned in the subsurface formation.

[1183] FIG. 170 depicts an embodiment of U-shaped nuclear heater assembly 2192. FIG. 171 depicts nuclear heater assembly 2192 positioned in a wellbore where only one end of the wellbore extends to the surface. Nuclear heater assembly 2192 may include outer conduit 2194.

Nuclear heater assembly 2192 may include one or more fuel conduits 2196. In some embodiments, is coiled tubing. Fuel conduit 2196 may be positioned in outer conduit 2194. Nuclear heater assembly 2192 may include one or more nuclear pebble heaters 2198. Nuclear pebble heaters 2198, nuclear modulators 2202, and/or nuclear reflectors 2200 may be positioned in fuel conduit 2196. Heat transfer fluid 2206 may be circulated past nuclear pebble heaters 2198. Heat transfer fluid 2206 may be circulated between the outer surface of fuel conduit 2196 and the inner surface of outer conduit 2194. Heat transfer fluid may be sealed inside fuel conduit 2196. Heat transfer fluid 2206 may distribute heat along the length of nuclear heater assembly 2192. In some embodiments, heat transfer fluid 2206 is helium gas. Nuclear pebble heaters 2198 may be circulated by heat transfer fluid 2206. Circulation of nuclear pebble heaters 2198 may maintain activation of the nuclear pebble heaters. Heat transfer fluid 2206 may push and/or carry nuclear pebble heaters, nuclear moderators, and/or nuclear reflectors to the surface of the wellbore.

[1184] In certain embodiments, fuel conduit 2196 is formed from a material that has high neutron reflectivity. Neutron reflective material may facilitate continuation of the nuclear reactions occurring in nuclear pebble heaters 2198 by reflecting neutrons that escape the nuclear pebble heaters back towards the originating nuclear pebble heaters or other nuclear pebble heaters positioned in fuel conduit 2196. Neutron reflective material may inhibit neutrons from escaping fuel conduit 2196 into the surrounding subsurface formation. Formation of radioactive isotopes in the subsurface formation adjacent to nuclear heater assembly 2192 may be limited and/or inhibited by surrounding nuclear pebble heaters 2198 with one or more conduits made out of neutron reflective material (for example, fuel conduit 2196 and outer conduit 2194).

[1185] An example of a neutron reflective material suitable for encasing nuclear pebble materials is iron. In certain embodiments, it may be important to ensure the iron used is relatively pure and avoid some common impurities and/or additives typically combined with iron (such as chromium used in stainless steel). Other elements that may be avoided in a fuel conduit include, but are not limited to, nickel, manganese and cobalt. Additional reflection of thermal neutrons from the carbon and hydrogen atoms in the hydrocarbon containing formation may increase the thermal neutron flux experienced by the nuclear pebble heaters.

[1186] In some embodiments, nuclear heater assembly 2192 includes outer conduit 2194. Fuel conduit 2196 may be positioned in outer conduit 2194 before and/or after the outer conduit has been positioned in the subsurface formation. In some embodiments, the nuclear heater assembly may be positioned in a casing in the sub surface formation. The casing may be cemented in the formation using a graphite based cement (for example 65% by weight graphite based cement). Graphite based cement may assist in maintaining application of a high thermal neutron flux to the

nuclear pebble heaters. In certain embodiments, outer conduit 2194 includes material that is complementary to the material in fuel conduit 2196. For example, fuel conduit 2196 may reflect neutrons but not be resistant to corrosion from fluids in the formation. Thus, outer conduit 2194 may be formed of a corrosion resistant material that may protect the fuel conduit from corrosive elements. In certain embodiments, outer conduit 2194 is formed from a corrosion resistant material such as stainless steel. In some embodiments, outer conduit 2194 is a composite iron or carbide and stainless steel (for example, an inside surface of outer conduit 2194 may be thick iron conduit and the outer surface of the outer conduit is stainless steel).

[1187] Commercially available nuclear pebble heater design typically includes low level enriched uranium triple-coated isotropic particles contained in a molded graphite sphere. A coated particle may include a kernel of uranium dioxide surrounded by four coating layers.

[1188] During the nuclear pebble heater fabrication process, a solution of uranyl nitrate is sprayed to form microspheres. The microspheres may then be gelled and calcined (baked at high temperature) to produce uranium dioxide fuel "kernels". The kernels are then run through a chemical vapor deposition oven. The chemical vapor deposition oven typically uses an argon environment at a temperature of about 1000 °C, and layers of specific chemicals are added with precision.

[1189] The first layer deposited on the kernels may be porous carbon, allowing fission products to collect without over-pressurizing the coated fuel particles. A second layer may include a thin coating of pyrolytic carbon. Pyrolytic carbon is a very dense form of heat-treated carbon. Following the second layer, a third layer of silicon carbide may be applied. The silicon carbide may function as a refractory material. Following the third layer, a fourth layer of pyrolytic carbon may be applied.

[1190] The porous carbon may accommodate any mechanical deformation that the uranium dioxide kernel may undergo during the lifetime of the nuclear pebble heater as well as accommodating gaseous fission products diffusing out of the kernel. The pyrolytic carbon and silicon carbide layers provide a barrier designed to contain the fuel and radioactive fission products resulting from nuclear reactions in the kernel.

[1191] In a typical nuclear pebble heater, about 15,000 coated particles are mixed with graphite powder and a phenolic resin and pressed into a spherical shape. The coated particles are about a millimeter in diameter. The resulting sphere is about 50 mm in diameter. A 5 mm thick layer of pure carbon may be added to form a "non-fuel" zone. The resulting spheres may be sintered and annealed to make them hard and durable. The spherical nuclear pebble heater may be machined to a uniform diameter of about 60 mm. Each nuclear pebble heater may include a total of about 9

g of uranium. In other embodiments, the size, number and composition of layers, and/or the amount of fissionable material may be different.

[1192] To have a self-sustaining reaction in the nuclear pebble heaters, the uranium in the nuclear pebble heaters may be enriched to include about 9% uranium-235, which is the isotope of uranium that undergoes fission in the nuclear pebble heaters. Uranium-235 occurs in natural uranium at a concentration of about 0.7%.

[1193] In some embodiments, nuclear pebble heaters 2198 are acquired new (for example, right after production and before they have been used in a nuclear reactor). Nuclear pebble heaters 2198 are currently produced for use in pebble bed reactors. Nuclear pebble heaters 2198 enriched with 9% uranium-235 may, in some embodiments, be too powerful, produce too much heat, and/or produce heat for too long a time. For example, current commercially produced nuclear pebble heaters have about 9 g of uranium, which equates to a heat production of about 950 watts per pebble. In some embodiments, nuclear heater assembly 2192 requires about 300 watts of energy per foot. Therefore, filling a majority of fuel conduit 2196 with nuclear pebble heaters 2198 capable of producing 950 watts each may produce more heat than necessary to heat the subsurface formation to a desired temperature. In certain embodiments, however, methods or steps may be taken to produce desired energy outputs per foot in nuclear heater assembly 2192.

[1194] In some embodiments, treatment of the subsurface formation requires heating the formation to a desired initial upper range (for example, from about 250 °C to about 350 °C). After heating the subsurface formation to the desired temperature range, the temperature may be maintained in the range for a desired time (for example, until a percentage of hydrocarbons have been pyrolyzed or an average temperature in the formation reaches a selected value). As the formation temperature rises, the heater temperature may be slowly lowered over a period of time. Currently, activated nuclear pebble heaters reach a natural heat output limit that results in a maximum temperature of the nuclear pebble heaters of about 900 °C. As the uranium-235 fuel in the nuclear pebble heaters is depleted, the maximum heat output available from the nuclear pebble heaters decreases. The natural energy output curve of nuclear pebble heaters may be used to provide a desired heating versus time profile for certain subsurface formations.

[1195] Placing the nuclear pebble heaters in a hydrocarbon-rich zone may be desirable. The nuclear pebble heaters may be designed to provide a maximum heat output equivalent to the heat losses into the formation.

[1196] The nuclear pebble heaters have a temperature self-limiting effect due to what is Doppler broadening. Doppler broadening is the broadening of spectral lines due to the Doppler effect. The Doppler effect is described as the thermal movement of atoms or molecules and how that thermal movement shifts the apparent frequency of each emitter. The many different velocities

of the thermal neutronsresult in many small shifts, the cumulative effect of which is to broaden the line. The resulting line profile is known as a Doppler profile. The broadening may be dependent only on the wavelength of the line, the mass of the emitting particle, and the temperature. As the of the nuclear pebble heater temperature increases, more thermal neutrons are absorbed by the uranium-238 atoms in the nuclear pebble heater, so less are available for fissioning the remaining uranium-235. In nuclear pebble heaters, the Doppler broadening effect reduces the power generated as the temperature of the nuclear pebble heaters increases.

[1197] When the nuclear pebble heater gets hotter, the accelerated motion of the atoms in the fuel increases the probability of neutron capture by uranium-238 atoms present in the nuclear pebble heater. Uranium-238, which typically forms the bulk of the uranium in the reactor, is much more likely to absorb fast neutrons. The neutrons absorbed by the uranium-238 reduces the number of neutrons available to cause remaining uranium-235 fission, thus reducing the power output by the nuclear pebble heater. This natural negative feedback limits the temperature that the individual nuclear pebble heaters can obtain.

[1198] As depicted in FIGS. 170-176, includes one or more neutron reflectors 2200 and/or neutron moderators 2202. Neutron moderators 2202 slow fast neutrons to thermal velocities that increase the likelihood of the neutrons to cause fission of uranium-235 nuclei. Nuclear heater assembly 2192 may include one or more spacers 2204 that are not involved in the nuclear process. Spacers 2204 may provide spacing between nuclear pebble heaters 2198 to control the amount of heat output per unit length provided by nuclear heater assembly 2192. Spacers may be made of alumina, silica or other material. Neutron reflectors 2200 and/or moderators 2202 may be positioned in fuel conduit 2196. Neutron moderators 2202 may be required to maintain sufficient thermal neutron flux of nuclear pebble heaters 2198 to sustain the fission reactions that produce heat.

[1199] Neutron reflectors 2200 may be formed from neutron reflective material. In some embodiments, neutron reflectors are formed from a similar material as is used to form fuel conduit 2196. For example, may be formed from iron, beryllium, tungsten carbide, graphite, or mixtures thereof. Neutron moderators may be formed from graphite. Neutron reflectors and/or neutron moderators may be solid or hollow. Hollow neutron reflectors may be used so that the neutron reflectors are appropriately sized without using excess material, as well as, reducing the weight, transport costs, and/or production costs of the neutron reflectors. The neutron reflectors may reflect neutrons generated by a nuclear reaction in nuclear pebble heaters 2198. In certain embodiments, neutron reflectors have a similar size and/or shape to nuclear pebble heaters 2198. Neutron reflectors and/or neutron moderators may be spherical or other easily moved shaped to facilitate placement and/or removal in nuclear heater assembly 2192.

[1200] Positioning one or more neutron reflectors and/or neutron moderators between nuclear pebble heaters 2198 in fuel conduit 2196 allows for the adjustment of the energy per unit length produced by the fuel conduit when the nuclear pebble heaters are positioned and activated. Activated nuclear pebble heaters 2198 have a decaying energy production curve over time. Nuclear pebble heaters are able to produce more energy earlier in their lifetime with their power output decreasing at a predictable rate throughout their lifetime. In some embodiments, as the power of a set of nuclear pebble heaters 2198 positioned in fuel conduit 2196 decreases over time, a number of neutron reflectors positioned between nuclear pebble heaters may be decreased. Decreasing the number of neutron reflectors may increase the density of nuclear pebble heaters (number of nuclear pebble heaters per unit length) in the fuel conduit and, thus, compensate for the natural decay of the nuclear pebble heaters over time. In some embodiments, as neutron reflectors are removed from the fuel conduit, additional nuclear pebble heaters may be positioned in the fuel conduit as required to achieve desired energy output.

[1201] As depicted in FIG. 172, nuclear pebble heaters 2198 may be positioned between nuclear moderators 2202 in a middle portion of fuel conduit 2202 of the heater assembly to regulate heat production at the middle of nuclear heater assembly 2192. In some embodiments nuclear moderators 2202 may be formed of graphite. The graphite may facilitate heat transfer and reflect neutrons. As depicted in FIG. 173, nuclear moderators 2202 may be positioned between every two nuclear pebble heaters 2198 at the end of fuel conduit 2202 of the heater assembly. In some embodiments nuclear moderators 2202 may be formed of graphite to facilitate heat transfer and reflect neutrons. In some embodiments, the density of nuclear pebble heaters is increased near the ends of the elements positioned in fuel conduit 2196 to compensate for heat loss and achieve the desired energy output. One or more neutron reflectors 2200 (for example, spheres including tungsten carbide) may be positioned as the end members of the elements positioned in fuel conduit re2196.

[1202] As depicted in FIG. 175, nuclear pebble heaters 2198, nuclear moderators 2202 and/or nuclear reflectors 2200 may be sized so to stack in fluid conduit 2202. Stacking or packing of nuclear pebble heaters 2198, nuclear moderators 2202 and/or nuclear reflectors 2200 may increase the solid angle thus increase heat production of the nuclear pebble heaters.

[1203] As depicted in FIG. 176, outer conduit 2194 may be positioned in graphite-based cement casing 2208. Outer conduit 2194 may include iron layer 2210 and stainless steel layer 2212. Iron layer 2210 may reflect neutrons. Stainless steel layer 2212 may be positioned between iron layer 2210 and casing 2208 to inhibit corrosion of iron layer 2210. Fuel conduit 2196 may include iron layer 2210' to reflect neutrons back to the nuclear pebble heaters. Nuclear pebble heaters 2198 may be positioned between nuclear moderators 2202. Nuclear reflectors 2200 may

be positioned at the ends of the series of n nuclear pebble heaters 2198 and nuclear moderators 2202.

[1204] In some embodiments, partially depleted nuclear pebble heaters are used to heat a subsurface formation. Nuclear pebble heaters 2198 may be acquired after they have been used for a time in a pebble bed modular reactor facility. The used nuclear pebble heaters 2198 may have their uranium-235 depleted from an initial value of about 9% to about 3%, from about 8% to about 4%, or from about 7% to about 5%. Partially depleted nuclear pebble heaters may produce less energy per nuclear pebble heater, which may allow the use of few or no nuclear reflectors in fuel conduit 2196. Typically, depleted or partially depleted nuclear pebble heaters are disposed of by underground storage in a proper facility (for example, encasing the reactors in concrete under the ground). Operators of pebble bed modular reactor facilities usually have to incur significant expenses to properly dispose of the used nuclear pebble heaters. Therefore, partially depleted nuclear pebble heaters may be acquired for little or no cost from pebble bed modular reactor facilities. Acquiring partially depleted nuclear pebble heaters for little or no cost may reduce the costs of developing and treating the hydrocarbon subsurface formation and may utilize material that would otherwise be considered to be useless. In some embodiments, overall costs for developing and treating the subsurface formation may be decreased by as much as 95% using nuclear pebble heaters due to the cost of the energy required to heat the subsurface formation being drastically reduced, even if the nuclear pebble heaters are purchased new. Moreover, less carbon dioxide will be emitted during the in situ heat treatment process when by using nuclear heaters as opposed to using electrical heaters, burners, or in situ combustion to heat the subsurface formation.

[1205] In some embodiments, as nuclear pebble heaters 2198 in fuel conduit 2196 are depleted in nuclear heater assembly 2192, additional fuel conduits may be positioned in the outer conduit as needed. In one embodiment, as nuclear pebble heaters in a first fuel conduit have depleted to such an extent that the first fuel conduit does not produce a desired amount of heat per unit length, the first fuel conduit may be pulled from the formation, and a second fuel conduit containing a second set of nuclear pebble heaters may be inserted into nuclear heater assembly 2192. The second fuel conduit and second set of nuclear pebble heaters may provide sufficient heat output to heat the formation as desired. In some embodiments, two or more fuel conduits containing nuclear pebble heaters may be positioned in the nuclear heater assembly to increase the heat output from the nuclear heater assembly. Outer conduit 2194 may have an initial size that accommodates two or more fuel conduits.

[1206] In some embodiment, nuclear pebble heaters 2198 are specifically designed for nuclear heater assembly 2192. Special order nuclear pebble heaters may be produced with an appropriate amount of enriched uranium for the desired heat output of nuclear heater assembly 2192.

[1207] In some embodiments, heat transfer fluid 2206 is used in nuclear heater assembly 2192. Heat transfer fluid 2206 may be supplied to outer conduit 2194 and function to ensure even heating of the subsurface formation from nuclear pebble materials 2198 in fuel conduit 2196. In some embodiments, one or more nuclear pebble heaters 2198 in fuel conduit 2196 may produce more energy than other nuclear pebble heaters in the fuel conduit leading to potential hot spots in the fuel conduit. Hot spots are areas where one or more nuclear pebble heaters are producing more heat than adjacent nuclear pebble heaters. Heat transfer fluid 2206 circulated through outer conduit 2194 over fuel conduit 2196 may help reduce the effect of hot spots along the fuel conduit. In certain embodiments, heat transfer fluid 2206 includes non-reactive fluids or non-radioactive isotope forming fluids. For example, heat transfer fluid 2206 may include helium gas. Helium gas may inhibit corrosion (for example, oxidation of carbon) of the nuclear pebble heaters at elevated temperatures. Convection and/or conduction of heat by helium gas may smooth temperature profile inside the nuclear heater assembly. In some embodiments, nuclear pebble heater positioning systems are used to periodically reposition activated nuclear pebble heaters 2198 in fuel conduit 2196, and to move the nuclear pebble heaters to prevent the development of hot spots.

[1208] In some embodiments, heat transfer fluid 2206 is sealed within outer conduit 2194 without the assistance of additional systems to help circulate the fluids. In certain embodiments, heat fluid circulation systems are employed to ensure heat transfer fluid 2206 is circulated evenly throughout outer conduit 2194. The circulation system may be positioned in nuclear heater assembly 2192 (for example, in the outer conduit). In some embodiments, the circulation system is positioned on the surface and exterior to the nuclear heater assembly.

[1209] In some embodiments, the circulation system is used to regulate the temperature of nuclear heater assembly 2192. For example, the circulation system may be used to remove heat produced by the nuclear pebble heaters to limit the heat output available to transfer to the formation. The amount of heat removed may be adjusted by controlling the flow rate of heat transfer fluid through the nuclear heater assembly. The heat removed by the heat transfer fluid may be converted to electricity (for example, using a Kalina and/or Rankine cycle) and/or used to heat other portions of the subsurface formation.

[1210] In some embodiments, nuclear pebble heaters 2198 require neutron activation before they will produce heat. Before activation, the nuclear pebble materials may not be thermally hot. In embodiments where unactivated nuclear pebble materials are employed in nuclear heater

DEMANDE OU BREVET VOLUMINEUX

LA PRÉSENTE PARTIE DE CETTE DEMANDE OU CE BREVET COMPREND PLUS D'UN TOME.

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JUMBO APPLICATIONS/PATENTS

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NOM DU FICHIER / FILE NAME :

NOTE POUR LE TOME / VOLUME NOTE:

WHAT IS CLAIMED IS:

1. A method for forming a longitudinal tubular, comprising:

longitudinally placing sides of a metal strip together or near to each other;

shield welding the sides of the metal strip to form the longitudinal tubular; and

flushing the region of the welding, before and/or during the welding, with an inert gas that inhibits oxidation of the tubular while the sides are being welded.

2. The method of claim 1, wherein the inert gas comprises argon.

3. The method of claim 1, wherein at least one gas is provided in a center of the longitudinal tubular being formed.

4. The method of claim 1, further comprising visually inspecting the welding through a window on the shield.

5. A method for forming an electrically resistance heater for a subsurface formation, comprising:

providing a metal strip that provides electrical resistance heat when a time-varying current is applied to the metal strip;

longitudinally placing sides of the metal strip together or near to teach other;

shield welding the sides of the metal strip to form the longitudinal tubular; and

flushing the region of the welding, before and/or during the welding, with an inert gas that inhibits oxidation of the tubular while the sides are being welded.

6. The method of claim 5, wherein the inert gas comprises argon.

7. The method of claim 5, wherein at least one gas is provided in a center of the longitudinal tubular being formed.

8. The method of claim 5, further comprising visually inspecting the welding through a window on the shield.

9. The method of claim 5, wherein the metal strip comprises a temperature limited heater, the temperature limited heater comprising a ferromagnetic conductor and is configured to provide, when a time varying current is applied to the temperature limited heater, and when the heater is below a selected temperature, an electrical resistance and, when the ferromagnetic conductor is at or above the selected temperature, the temperature limited heater automatically provides a reduced electrical resistance.

10. The method of claim 5, wherein the metal strip comprises:

a ferromagnetic conductor; and

an electrical conductor electrically coupled to the ferromagnetic conductor, wherein the ferromagnetic conductor is positioned relative to the electrical conductor such that an electromagnetic field produced by time-varying current flow in the ferromagnetic conductor

confines a majority of the flow of the electrical current to the electrical conductor at temperatures below or near a selected temperature.

11. A heater for a subsurface formation, comprising a shield welded longitudinal electrical resistance heater, the heater being configured to provide a heating section that is at least 10 m in length.

12. The heater of claim 11, wherein the heater is configured to be coiled.

13. The heater of claim 11, wherein the heater comprises a temperature limited heater, the temperature limited heater comprising a ferromagnetic conductor and is configured to provide, when a time varying current is applied to the temperature limited heater, and when the heater is below a selected temperature, an electrical resistance and, when the ferromagnetic conductor is at or above the selected temperature, the temperature limited heater automatically provides a reduced electrical resistance.

14. The heater of claim 11, wherein the heater comprises:

a ferromagnetic conductor; and

an electrical conductor electrically coupled to the ferromagnetic conductor, wherein the ferromagnetic conductor is positioned relative to the electrical conductor such that an electromagnetic field produced by time-varying current flow in the ferromagnetic conductor confines a majority of the flow of the electrical current to the electrical conductor at temperatures below or near a selected temperature.

15. A system for coupling ends of elongated heaters, comprising:

two elongated heaters with an end portion of one heater abutted or near to an end portion of the other heater, the elongated heaters comprising cores and one or more conductors substantially concentrically surrounding the cores, the cores having a lower melting point than the conductors, at least one end portion of at least one conductor having a beveled edge, and at least one end portion of at least one core having a recessed opening;

a core coupling material at least partially inside the recessed opening, the core coupling material extending between the two elongated heaters; and

wherein the gap formed by the beveled edge is configured to be filled with a coupling material for coupling the one or more conductors.

16. The system of claim 15, wherein the end portions of both conductors have beveled edges.

17. The system of claim 15, wherein the end portions of both cores have recessed openings.

18. The system of claim 15, wherein the core comprises copper.

19. The system of claim 15, wherein the core coupling material comprises copper.

20. The system of claim 15, wherein at least one conductor comprises ferromagnetic material.

21. The system of claim 15, wherein the outermost conductor comprises stainless steel.

22. The system of claim 15, wherein the coupling material comprises a non-ferromagnetic material.

23. The system of claim 15, wherein the elongated heaters comprises cores substantially concentrically surrounded by ferromagnetic conductors, the ferromagnetic conductors substantially concentrically surrounded by an outer electrical conductor.

24. The system of claim 15, wherein the elongated heaters are configured to be coupled by welding together the conductors with the coupling material in the gap formed by the beveled edges.

25. The system of claim 15, wherein electrical current is configured to flow through the core coupling material when an electrical current is applied to the elongated heaters.

26. A method for coupling two elongated heaters, comprising:

placing a core coupling material in recesses in the end portions of cores of the two elongated heaters, the cores of the heaters substantially concentrically surrounded by one or more conductors, the cores having a lower melting point than the one or more conductors; and

coupling the end portions of the two heaters by filling gaps between beveled edges of the end portions of the one or more conductors with a coupling material.

27. A system for coupling end portions of two elongated heaters, comprising:

a holding system configured to hold end portions of the two elongated heaters so that the end portions of the elongated heaters are abutted together or located near each other;

a shield for enclosing the abutted end portions of the heaters, the shield configured to inhibit oxidation during welding to join the end portions together, the shield comprising a hinged door that, when closed, is configured to at least partially isolate the interior of the shield from the atmosphere, and the hinged door, when open, is configured to allow access to the interior of the shield; and

one or more inert gas inlets configured to provide at least one inert gas to flush the system with inert gas during welding of the end portions of the heaters.

28. The system of claim 27, further comprising at least one source of inert gas.

29. The system of claim 27, wherein the inert gas comprises argon.

30. The system of claim 27, wherein the shield comprises a window configured to allow an operator of the system to view the welding of the end portions.

31. The system of claim 27, wherein the shield, when closed, forms an air tight seal to seal off the interior of the shield from the atmosphere.

32. A heater, comprising:

a ferromagnetic conductor; and

an electrical conductor electrically coupled to the ferromagnetic conductor;

wherein the heater is configured to provide a first amount of heat at a lower temperature and, the heater is configured to provide a second reduced amount of heat when the heater reaches a selected temperature, or enters a selected temperature range, at which the ferromagnetic conductor undergoes a phase transformation.

33. The heater of claim 32, wherein the ferromagnetic conductor is positioned relative to the outer electrical conductor such that an electromagnetic field produced by time-varying current flow in the ferromagnetic conductor confines a majority of the flow of the electrical current to the outer electrical conductor at temperatures below or near the selected temperature.

34. The heater of claim 32, wherein the electrical conductor provides a majority of a resistive heat output of the heater at temperatures up to approximately the selected temperature, or the selected temperature range of the phase transformation of the ferromagnetic conductor.

35. The heater of claim 32, wherein the phase transformation comprises a crystalline phase transformation.

36. The heater of claim 32, wherein the phase transformation comprises a change in the crystal structure of the ferromagnetic material.

37. The heater of claim 32, wherein the phase transformation comprises the transformation of the ferromagnetic conductor from ferrite to austenite.

38. The heater of claim 32, wherein the heater self-limits at a temperature near the phase transformation temperature or temperature range.

39. The heater of claim 32, wherein the phase transformation is reversible.

40. The heater of claim 32, wherein the ferromagnetic conductor comprises additional material configured to adjust the selected temperature, or the selected temperature range, of the ferromagnetic conductor.

41. The heater of claim 40, wherein the alloy addition is configured to adjust the width of the temperature range of the phase transformation.

42. The heater of claim 40, wherein the heater has a turndown ratio of at least 2 to 1.

43. A method for treating a hydrocarbon containing formation, comprising:

providing heat for a selected time to a first hydrocarbon layer in the formation from a first heater located in an opening in the formation, the opening having a first end portion at a first location on the surface of the formation and a second end portion at a second location on the surface of the formation, the first heater having a substantially horizontal portion located in the first hydrocarbon layer in the formation and relatively vertical portions extending between the substantially horizontal portion and the first and second locations on the surface;

uncoupling the relatively vertical portions of the first heater from the substantially horizontal portion of the first heater;

removing the relatively vertical portions of the first heater from the opening;

placing an impermeable material in the relatively vertical portions of the opening such that the impermeable material at least partially isolates the opening above the first hydrocarbon layer;

forming an additional substantially horizontal opening portion in a second hydrocarbon layer, the additional substantially horizontal opening portion coupling between the relatively vertical portions of the opening, the second hydrocarbon layer being separated from the first hydrocarbon layer by an at least partially impermeable layer;

placing a second heater in the additional substantially horizontal opening portion; and

providing heat from the second heater to the second hydrocarbon layer.

44. The method of claim 43, further comprising producing fluids from the formation.

45. The method of claim 43, wherein the selected time is sufficient time to produce a selected amount of hydrocarbons from the first hydrocarbon layer.

46. The method of claim 43, further comprising abandoning the first hydrocarbon layer after treating the formation by leaving the packing in place in the opening.

47. The method of claim 43, wherein the relatively vertical portions of the first heater are uncoupled from the substantially horizontal portion of the first heater by breaking one or more connections to the first heater.

48. The method of claim 47, wherein the breaking is performed by pulling one or more of the relatively vertical portions with a sufficient amount of force.

49. The method of claim 43, wherein the formation comprises an oil shale formation.

50. The method of claim 43, wherein the first hydrocarbon layer has a higher richness than the second hydrocarbon layer.

51. The method of claim 43, wherein the first hydrocarbon layer is at a greater depth than the second hydrocarbon layer.

52. The method of claim 43, wherein the impermeable material provides an impermeable layer between the first hydrocarbon layer and the second hydrocarbon layer.

53. A method for producing hydrocarbons from a subsurface formation, comprising:

providing heat to the subsurface formation;

forming one or more particles, wherein the particles are formed during heating of the subsurface formation; and

producing a fluid comprising hydrocarbons and the particles from the subsurface formation.

54. The method of claim 53, wherein a majority of the particles have a diameter ranging between 0.5 microns and 200 microns.

55. The method of claim 53, wherein the particles have an average diameter between 0.5 microns and 200 microns.

56. The method of claim 53, wherein one or more of the particles is a zeolite.

57. The method of claim 53, wherein forming one or more particles produces a bimodal distribution of particles.

58. The method of claim 53, wherein forming one or more particles produces a trimodal distribution of particles.

59. The method of claim 53, further comprising removing particles from the produced fluid.

60. The method of claim 53, further comprising filtering the produced fluid to remove selected particles.

61. The method of claim 53, further comprising centrifuging the produced fluid to remove selected particles.

62. The method of claim 53, further comprising treating the produced fluid to agglomerate selected particles, and then removing the agglomerated particles from the produced fluid.

63. A method of producing jet fuel, comprising:

providing formation fluid from a subsurface in situ conversion process;

separating a liquid stream from the formation fluid;

hydrotreating the liquid stream; and

separating the liquid stream to produce jet fuel.

64. A method treating a hydrocarbon containing formation, comprising:

providing heat to the formation from one or more heaters;

allowing heat to transfer from the heaters to a portion of the formation;

producing fluids comprising hydrocarbons from the formation;

treating the produced fluids to remove heat from the produced fluids; and

generating electricity from the heat using a Kalina cycle.

65. The method of claim 64, wherein the Kalina cycle comprises a modified Kalina cycle.

66. The method of claim 64, wherein the Kalina cycle comprises evaporating aqueous ammonia using the heat.

67. The method of claim 64, wherein the Kalina cycle comprises generating a rich ammonia gas stream.

68. The method of claim 64, further comprising using the electricity for electrical resistance heaters in the formation, or in another formation.

69. A method of treating a hydrocarbon containing formation, comprising:

providing heat to the formation from one or more heaters;

allowing heat to transfer from the heaters to a portion of the formation;

producing fluids comprising nahcolite or nahcolite products from the formation;

treating the produced fluids to remove heat from the produced fluids; and

generating electricity from the heat using a Kalina cycle.

70. The method of claim 69, wherein the Kalina cycle comprises a modified Kalina cycle.

71. The method of claim 69, wherein the Kalina cycle comprises evaporating aqueous ammonia using the heat.

72. The method of claim 69, wherein the Kalina cycle comprises generating a rich ammonia gas stream.

73. The method of claim 69, further comprising using the electricity for electrical resistance heaters in the formation, or in another formation.

74. The method of claim 69, further comprising producing fluids comprising hydrocarbons from the formation.

75. A method of treating heat from a hydrocarbon containing formation, comprising:

providing heat to the formation from one or more heaters;

applying electrical current to at least a portion of the heaters;

allowing heat to transfer from the heaters to a portion of the formation;

producing fluids comprising hydrocarbons from the formation; and

treating the produced fluids to remove heat from the produced fluids;

generating electricity from the heat using a Kalina cycle.

76. The method of claim 75, wherein the Kalina cycle comprises a modified Kalina cycle.

77. The method of claim 75, wherein the Kalina cycle comprises evaporating aqueous ammonia using the heat.

78. The method of claim 75, wherein the Kalina cycle comprises generating a rich ammonia gas stream.

79. The method of claim 75, further comprising using the electricity for electrical resistance heaters in the formation, or in another formation.

80. A system for inhibiting fluids from condensing into a heated portion of an opening in a subsurface formation, comprising:

an elongated cylinder extending longitudinally along a length of the opening;

a baffle in the opening or the elongated cylinder, the baffle comprising a lower end portion that tapers to a reduced inside cross-sectional area at or near the bottom of the baffle; and

one or more movable objects located in the space between the baffle and the elongated cylinder, the movable objects sized to remain above the lower end portion of the baffle, the movable objects being configured to inhibit fluids from flowing above the baffle.

81. The system of claim 80, wherein the movable objects are sized to inhibit convection of fluids.

82. The system of claim 80, wherein one or more of the movable objects have rounded edges.

83. The system of claim 80, wherein one or more of the movable objects is substantially spherical.

84. The system of claim 80, wherein the movable objects are sized to fall into the portion of the opening below the baffle when the elongated cylinder is removed from the opening.

85. The system of claim 80, wherein the movable objects are configured to allow the elongated cylinder to be removed from the opening.

86. The system of claim 80, wherein the reduced inside cross-sectional area of the baffle is sized to allow the elongated cylinder to be moved through the baffle.

87. The system of claim 80, wherein the movable objects comprise silicon nitride.

88. The system of claim 80, wherein the movable objects are configured to withstand temperatures above about 160 °C.

89. The system of claim 80, wherein the movable objects comprise balls.

90. The system of claim 80, wherein the movable objects comprise various size objects.

91. The system of claim 90, wherein movable objects with larger sizes are placed nearer the lower portion of the baffle.

92. The system of claim 80, wherein the baffle is located in an overburden portion of the formation.

93. A method for forming a barrier around a treatment area in a subsurface formation, comprising:

providing sulfur into one or more wells located inside a perimeter of a treatment area in the formation, wherein the treatment area has a permeability of at least 0.1 darcy;

allowing the sulfur to diffuse towards portions of the formation cooler than the one or more wells; and

allowing the sulfur to solidify to form a barrier surrounding the treatment area.

94. The method of claim 93, wherein the barrier formed is an impermeable barrier.

95. The method of claim 93, wherein the treatment area has a permeability of at least 1 darcy.

96. The method of claim 93, wherein the treatment area has a permeability of at least 10 darcy.

97. The method of claim 93, wherein the treatment area has a permeability of at least 100 darcy.

98. The method of claim 93, wherein the permeability of the treatment has been increased by an in situ conversion process.

99. The method of claim 93, wherein the permeability of the treatment has been increased by a solution mining process.

100. The method of claim 93, wherein the sulfur is provided as a gas.

101. The method of claim 93, wherein the sulfur is provided as a liquid, and the heat of the formation inside the treatment area vaporizes the sulfur.

102. The method of claim 93, wherein the flow of sulfur is directed towards the perimeter of the treatment area.

103. The method of claim 93, wherein the wells are located near the perimeter of the treatment area.

104. The method of claim 93, wherein a low temperature barrier at least partially surrounding the treatment area enhances the solidification of the sulfur to form the barrier.

105. The method of claim 93, further comprising providing heat to the formation.

106. The method of claim 93, further comprising producing fluids comprising hydrocarbons from the formation.

107. The method of claim 93, further comprising cooling a region of the formation near the location that the sulfur is provided to the formation.

108. A method for providing hydrogen sulfide to a subsurface formation, comprising:

providing heat from one or more heaters to a portion of a subsurface formation;

producing fluids from the formation, wherein the produced fluids comprise hydrogen sulfide;

removing the hydrogen sulfide from the produced fluids; and

introducing the hydrogen sulfide into the formation, or into another formation, through one or more wellbores at a pressure below a lithostatic pressure of the formation in which the hydrogen sulfide is introduced.

109. The method of claim 108, wherein the injected hydrogen sulfide forms a sulfide layer on the surface of the walls of the wellbores.

110. The method of claim 108, wherein the hydrogen sulfide reacts in the formation.

111. The method of claim 108, wherein the hydrogen sulfide is sequestered in the formation.

112. A method for providing carbon dioxide to a subsurface formation, comprising:

providing heat from one or more heaters to a portion of a subsurface formation;

producing fluids from the formation, wherein the produced fluids comprise carbon dioxide;

removing the carbon dioxide from the produced fluids;

introducing the carbon dioxide into the formation, or into another formation, through one or more wellbores; and

introducing a basic fluid in the wellbores used for carbon dioxide introduction to inhibit corrosion in the wellbores.

113. The method of claim 112, wherein the carbon dioxide reacts in the formation.

114. The method of claim 112, wherein the carbon dioxide is sequestered in the formation.

115. A method of preparing a wrought metal material, comprising:

providing a section of cast pipe, wherein the section comprises, by weight: about 18% to about 22% chromium, about 12% to about 13% nickel, about 0 to about 4.5% copper, about 1% to about 5% manganese, about 0.3% to about 1% silicon, about 0 to about 1% niobium, about 0.3% to about 1% molybdenum, about 0.08% to about 0.2% carbon, about 0.2% to about 0.5% nitrogen, about 0 to about 2% tungsten, with the balance being iron;

heat treating the section of cast pipe;

cold rolling the treated section of pipe;

heat treating the cold rolled section to produce the wrought material; and

wherein the wrought material comprises at least 3% by weight of stable fine-grain microstructures at about 800 °C.

116. The method of claim 115, wherein the section comprises about 40% to about 75% iron.

117. The method of claim 115, wherein the section comprises about 47% to about 69% iron.

118. The method of claim 115, wherein heat treating the section of cast pipe comprises heat treating the section at or above about 1200 °C for at least 1.5 hours.

119. The method of claim 115, wherein heat treating the section of cast pipe comprises heat treating the section at or above about 1250 °C for at least 3 hours.

120. The method of claim 115, wherein heat treating the section of cast pipe comprises:

heat treating the section of cast pipe;

hot rolling the heat treated section; and

annealing the hot rolled section.

121. The method of claim 120, wherein hot rolling comprises rolling the heat treated section of pipe at or above about 1200 °C to a thickness of at least 0.75 inches.

122. The method of claim 120, wherein hot rolling comprises rolling the heat treated section of pipe at or above about 1200 °C to a thickness of at least 1 inch.

123. The method of claim 120, wherein annealing comprises heating the hot rolled section at or above about 1200 °C for at least about 15 minutes.

124. The method of claim 115, wherein heat treating the cold rolled section comprises annealing the cold rolled section at or above about 1250 °C for at least about 1 hour and heating the annealed section at or above about 1250 °C for at least about 1 hour.

125. The method of claim 115, wherein heat treating the cold rolled section comprises annealing the cold rolled section at or above about 1200 °C for at least about 1 hour and heating the annealed section at or above about 1250 °C for at least 1 hour.

126. The method of claim 115, wherein heat treating the cold rolled section is performed in air under an argon cover.

127. The method of claim 115, further comprising sandblasting the hot rolled section of pipe.

128. The method of claim 115, wherein the wrought material comprises at least 1.5% by weight of stable fine-grain microstructures at about 900 °C.

129. The method of claim 115, wherein the wrought material comprises at least 0.5% by weight of stable fine-grain microstructures at about about 1250 °C.

130. The method of claim 115, wherein a yield strength at about 900°C of the wrought material is greater than 75% the yield strength of the wrought material at about 650°C.

131. The method of claim 115, wherein a tensile strength of the wrought material is greater than the tensile strength of the same material as a cast alloy.

132. A wrought material composition, comprising about 18% to about 22% chromium; about 12% to about 13% nickel; about 0 to about 4.5% copper; about 1% to about 5% manganese; about 0.3% to about 1% silicon; about 0 to about 1% niobium; about 0.3% to about 1% molybdenum; about 0.08% to about 0.2% carbon; about 0.2% to about 0.5% nitrogen, about 0 to about 2% tungsten; with the balance being iron.

133. The wrought material of claim 132, wherein the wrought material comprises about 20% chromium, about 3% copper, about 4% manganese, about 0.3% molybdenum, about 0.77% niobium, about 13% nickel, about 0.5% silicon, about 1% tungsten, about 0.09% carbon, and about 0.26% nitrogen, with the balance being iron.

134. The wrought material of claim 132, wherein the wrought material comprises about 19% chromium, about 4.2% manganese, about 0.3% molybdenum, about 0.8% niobium, about 12.5% nickel, about 0.5% silicon, about 0.09% carbon, about 0.24% nitrogen by weight with the balance being iron.

135. The wrought material of claim 132, wherein the wrought material comprises at least 3% by weight of stable fine-grain microstructures at about 800 °C.

136. The wrought material of claim 132, wherein the wrought material comprises at least 1.5% by weight of stable fine-grain microstructures at about 900 °C.

137. The wrought material of claim 132, wherein the wrought material comprises at least 0.5% by weight of stable fine-grain microstructures at about 1250 °C.

138. An improved alloy composition, comprising: about 18% to about 22% chromium; about 12% to about 13% nickel; about 0 to about 4.5% copper; about 1% to about 5% manganese;

about 0.3% to about 1% silicon; about 0 to about 1% niobium; about 0.3% to about 1% molybdenum; about 0.08% to about 0.2% carbon; about 0.2% to about 0.5% nitrogen: about 0 to about 2% tungsten; with the balance being iron.

139. The composition of claim 138, wherein the improved alloy comprises about 20% chromium, about 3% copper, about 4% manganese, about 0.3% molybdenum, about 0.77% niobium, about 13% nickel, about 0.5% silicon, about 1% tungsten, about 0.09% carbon, and about 0.26% nitrogen, with the balance being iron.

140. The composition of claim 138, wherein the improved alloy comprises about 19% chromium, about 4.2% manganese, about 0.3% molybdenum, about 0.8% niobium, about 12.5% nickel, about 0.5% silicon, about 0.09% carbon, about 0.24% nitrogen by weight, with the balance being iron.

141. A heater configured to provide heat to a subsurface formation, the heater comprising at least a section of elongated material comprising:

by weight: about 18% to about 22% chromium, about 12% to about 13% nickel, about 0 to about 4.5% copper, about 1% to about 5% manganese, about 0.3% to about 1% silicon, about 0 to about 1% niobium, about 0.3% to about 1% molybdenum, about 0.08% to about 0.2% carbon, about 0.2% to about 0.5% nitrogen, about 0 to about 2% tungsten, with the balance being iron.

142. A method of heating a subsurface formation using a heater comprising at least a section of elongated material comprising:

by weight: about 18% to about 22% chromium, about 12% to about 13% nickel, about 0 to about 4.5% copper, about 1% to about 5% manganese, about 0.3% to about 1% silicon, about 0 to about 1% niobium, about 0.3% to about 1% molybdenum, about 0.08% to about 0.2% carbon, about 0.2% to about 0.5% nitrogen, about 0 to about 2% tungsten, with the balance being iron.

143. A method of treating a hydrocarbon containing formation, comprising:

forming a perimeter barrier, wherein the perimeter barrier at least partially surrounds a portion of a treatment area of the hydrocarbon containing formation;

removing a portion of non-hydrocarbon materials from the treatment area;

injecting a fluid into the treatment area for combustion of at least a portion of the treatment area; and

producing formation fluid from one or more production wells.

144. The method of claim 143, wherein least one production well is positioned proximate the perimeter barrier.

145. The method of claim 143, wherein the perimeter barrier is formed by applying a heat transfer fluid to one or more freeze wells.

146. The method of claim 143, wherein removing a portion of non-hydrocarbon materials comprises solution mining.

147. The method of claim 143, wherein removing a portion of non-hydrocarbon materials comprises removing nahcolite.

148. The method of claim 143, wherein injecting a fluid into the treatment area comprises injecting an oxidant.

149. The method of claim 143, wherein injecting a fluid into the treatment area comprises injecting steam, wherein the steam is heated to at least 300 °C.

150. The method of claim 143, further comprising producing water from one or more of the production wells.

151. The method of claim 143, further comprising venting gases from the treatment area, wherein the gases are formed after combustion of the portion of the treatment area.

152. The method of claim 143, further comprising heating at least a portion of the treatment area using one or more subsurface heaters.

153. A method of treating a hydrocarbon containing formation, comprising:

forming a perimeter barrier, wherein the perimeter barrier at least partially surrounds a portion of a treatment area of the hydrocarbon containing formation;

removing a portion of non-hydrocarbon materials from the treatment area;

injecting a fluid into the treatment area for combustion of at least a portion of the treatment area;

heating at least a portion of the treatment area using one or more subsurface heaters; and

producing formation fluid from one or more production wells.

154. The method of claim 153, wherein least one production well is positioned proximate the perimeter barrier.

155. The method of claim 153, wherein the perimeter barrier is formed by applying a heat transfer fluid to one or more freeze wells.

156. The method of claim 153, wherein removing a portion of non-hydrocarbon materials comprises removing nahcolite.

157. The method of claim 153, wherein injecting a fluid into the treatment area comprises injecting an oxidant.

158. The method of claim 153, wherein injecting a fluid into the treatment area comprises injecting steam, wherein the steam is heated to at least 300 °C.

159. The method of claim 153, further comprising producing water from one or more of the production wells.

160. A heater comprising an exposed metal section comprising:

stainless steel of at least 2.0% cobalt by weight; and

wherein the composition of the exposed metal section is such that sulfidation rate of the metal section is less than about 25 mills per year at a temperature between about 800 °C to about 880 °C.

161. The heater of claim 160, wherein the stainless steel is at most 10% by weight cobalt.

162. The heater of claim 160, wherein the stainless steel is 410 stainless steel.

163. The heater of claim 160, wherein the exposed metal section is substantially inert to galvanic corrosion.

164. The heater of claim 160, wherein the exposed metal section comprises a temperature limited heater section.

165. The heater of claim 160, wherein the exposed metal section is the only electrical path in the heater configured to carry current into and out of a subsurface formation.

166. A system configured to heat a subsurface formation, comprising:

a heater comprising an exposed metal elongated heater section, wherein the heater is located in an opening in the formation, the heater section being configured to heat the subsurface formation, and wherein the composition of the exposed metal elongated heater section is such that sulfidation rate of the section decreases with increasing temperature of the heater at least from about 530 °C to about 650 °C.

167. The system of claim 166, wherein the exposed metal elongated heater section is 410 stainless steel.

168. The system of claim 166, wherein the exposed metal elongated heater section comprises at least 2.0% cobalt by weight.

169. The system of claim 166, wherein the exposed metal elongated heater section comprises at most 10% by weight cobalt.

170. The system of claim 166, wherein the exposed metal elongated heater section is substantially inert to galvanic corrosion.

171. The system of claim 166, wherein the exposed metal elongated heater section comprises a temperature limited heater section.

172. The system of claim 166, wherein the exposed metal elongated heater section is the only electrical path in the heater configured to carry current into and out of the formation.

173. A method for heating a subsurface formation using a heater comprising an exposed metal elongated heater section, wherein the composition of the exposed metal elongated heater section

is such that sulfidation rate of the section decreases with increasing temperature of the heater at least from about 530 °C to about 650 °C.

174. A system for heating a hydrocarbon containing formation, comprising:

a conduit located in an opening in the formation, the conduit comprising ferromagnetic material;

an electrical conductor positioned inside the conduit, and electrically coupled to the conduit at or near an end portion of the conduit so that the electrical conductor and the conduit are electrically coupled in series and electrical current flows in the electrical conductor in a substantially opposite direction to electrical current flow in the conduit during application of electrical current to the system;

wherein, during application of electrical current to the system, the flow of electrons is substantially confined to the inside of the conduit by the electromagnetic field generated from electrical current flow in the electrical conductor so that the outside surface of the conduit is at or near substantially zero potential at 25 °C; and

the conduit is configured to generate heat and heat the formation during application of electrical current to the system.

175. The system of claim 174, wherein the outside of the conduit is substantially electrically isolated from the formation.

176. The system of claim 174, wherein the conduit is proximate the formation.

177. The system of claim 174, wherein the conduit is proximate the formation such that heat generated in the conduit wall transfers to the formation.

178. The system of claim 174, wherein the conduit is configured to generate a majority of the heat output of the system.

179. The system of claim 174, wherein the conduit has an outer circumference that is greater than an outer circumference of the electrical conductor, and heat generated in the conduit wall transfers from the outer circumference of the conduit to the formation.

180. The system of claim 174, wherein the conduit has a wall thickness of at least one skin depth of the ferromagnetic material at 25 °C.

181. The system of claim 174, wherein the conduit is electrically isolated from at least one adjacent conduit located in the formation.

182. The system of claim 174, wherein the opening has a first end portion at a first location on the surface of the formation and a second end portion at a second location on the surface of the formation.

183. The system of claim 174, wherein a majority of the conduit is oriented substantially horizontally in a hydrocarbon layer of the formation.

184. The system of claim 174, wherein the electrical conductor is substantially electrically isolated from the conduit along a length of the conduit, and the electrical conductor is electrically coupled to the conduit near an end portion of the conduit.

185. The system of claim 174, wherein the system further comprises one or more centralizers to electrically separate the conduit from the electrical conductor.

186. The system of claim 174, wherein the system further comprises a thin electrically insulating layer on a surface of the conduit and/or on the outside surface of the electrical conductor.

187. The system of claim 174, wherein the conduit is configured to provide a first heat output below the Curie temperature of the ferromagnetic member, the conduit being configured to automatically provide a second heat output approximately at and above the Curie temperature of the ferromagnetic member, and the second heat output is reduced compared to the first heat output.

188. The system of claim 174, wherein the electrical conductor is an insulated conductor, the insulated conductor including an electrically conductive core inside an electrically conductive sheath with electrical insulation between the core and the sheath.

189. The system of claim 188, wherein the core is copper and the sheath is non-ferromagnetic stainless steel.

190. The system of claim 174, wherein the system has a turndown ratio of at least 2 to 1.

191. The system of claim 174, wherein the conduit has a length of at least 500 m and is in a hydrocarbon layer of the formation.

192. The system of claim 174, wherein the conduit is configured to allow a fluid to flow through the conduit to preheat the conduit and the system.

193. The system of claim 174, wherein the conduit is configured to allow a fluid to flow through the conduit to recover heat from the system.

194. The system of claim 174, wherein the electrical conductor is a tubular conductor with openings at or near an end portion of the electrical conductor, the openings being configured to allow a fluid to flow between the inside of the electrical conductor and the conduit.

195. A method of heating a subsurface formation, comprising:

providing a conduit to an opening in the formation, wherein the conduit comprises ferromagnetic material;

positioning an electrical conductor inside the conduit;

providing the conduit so that the conduit is electrically coupled at or near an end portion of the conduit so that the electrical conductor and the conduit are electrically coupled in series and electrical current flows in the electrical conductor in a substantially opposite direction to electrical current flow in the conduit during application of electrical current to the system;

applying electrical current to the conduit to generate heat in the conduit, wherein, during application of electrical current, the flow of electrons is substantially confined to the inside of the conduit by the electromagnetic field generated from electrical current flow in the electrical conductor so that the outside surface of the conduit is at or near substantially zero potential at 25 °C; and

allowing heat to transfer from the conduit to at least a portion of the formation.

196. The method of claim 195, wherein the subsurface formation comprises hydrocarbons, the method further comprising allowing the heat to transfer to the formation such that at least some hydrocarbons are pyrolyzed in the formation.

197. The method of claim 195, further comprising providing a hot heat transfer fluid to the conduit to provide heat to the formation.

198. The method of claim 197, wherein the hot heat transfer fluid comprises heated water, steam, and/or heated carbon dioxide.

199. The method of claim 195, further comprising producing a fluid from the formation.

200. The method of claim 195, further comprising providing a fluid to the conduit to recover heat from the system.

201. The method of claim 195, further comprising unspooling the conduit and the electrical conductor from one or more spools.

202. The method of claim 195, further comprising substantially electrically isolating the outside of the conduit from the formation.

203. The method of claim 195, wherein the conduit is provided to the opening such that a majority of the heat output is generated in the conduit wall, and such heat output transfers to the formation.

204. A transportation fuel made by a method, comprising:

providing a conduit to an opening in the formation, wherein the conduit comprises ferromagnetic material;

positioning an electrical conductor inside the conduit;

providing the conduit so that the conduit is electrically coupled at or near an end portion of the conduit so that the electrical conductor and the conduit are electrically coupled in series and electrical current flows in the electrical conductor in a substantially opposite direction to electrical current flow in the conduit during application of electrical current to the system;

applying electrical current to the conduit to generate heat in the conduit, wherein, during application of electrical current, the flow of electrons is substantially confined to the inside of the conduit by the electromagnetic field generated from electrical current flow in the electrical

conductor so that the outside surface of the conduit is at or near substantially zero potential at 25 °C;

allowing heat to transfer from the conduit to at least a portion of the formation;

producing a fluid from the formation; and

producing the transportation fuel from at least some of the produced fluid.

205. A method for treating an oil shale formation comprising nahcolite, the method comprising:

providing a first fluid to a portion of the formation through at least two injection wells;

producing a second fluid from the portion through at least one injection well until at least two injection wells are interconnected such that fluid can flow between the two injection wells, wherein the second fluid includes at least some nahcolite dissolved in the first fluid;

injecting the first fluid through one of the interconnected injection wells;

producing the second fluid from at least one of the interconnected injection wells;

providing heat from one or more heaters to the formation to heat the formation; and

producing hydrocarbon fluids from the formation.

206. The method of claim 205, further comprising leaving a section of substantially impermeable material to the side of the portion to inhibit fluid flow into or out of the portion.

207. The method of claim 205, further comprising leaving a section of substantially impermeable material above the portion to inhibit fluid flow into or out of the portion.

208. The method of claim 205, further comprising forming a barrier that extends into the impermeable material.

209. The method of claim 205, wherein at least one well used to introduce the first fluid into the portion and/or to remove the second fluid from the portion is also used to remove hydrocarbon containing fluid from the portion.

210. The method of claim 205, wherein introducing the first fluid comprises introducing the first fluid through a first injection well and a second injection well, wherein the introduction of the first fluid increases the permeability of the portion adjacent to the first injection well and the second injection well, and where the increased permeability adjacent the first injection well overlaps the increased permeability adjacent the second injection well to allow introduction of the first fluid through the first injection well and removal of the second fluid through the second injection well.

211. The method of claim 205, wherein the first fluid comprises hot water.

212. The method of claim 205, wherein heat used to heat the first fluid is recovered from a previously treated portion of the formation.

213. The method of claim 205, wherein producing the second fluid from the portion causes selection vertical shifting of the portion such that the hydrocarbon richness of the portion that has been vertically shifted is increased.

214. The method of claim 205, further comprising introducing at least some of the second fluid into a second portion of the formation and producing a third fluid comprising soda ash from the second portion.

215. The method of claim 214, further comprising absorbing at least a portion of carbon dioxide generated during conversion of sodium bicarbonate to soda ash into the second portion.

216. The method of claim 205, further comprising flowing at least some of the second fluid into and out of wellbores in the formation to transfer heat to the second fluid, wherein the transferred heat converts at least a portion of the sodium bicarbonate in the second fluid to soda ash.

217. The method of claim 205, further comprising heating the portion with heat sources to a temperature above a pyrolysis temperature of hydrocarbons in the portion, and producing hydrocarbons from the portion.

218. The method of claim 217, further comprising processing at least a portion of the hydrocarbons to produce one or more crude products; and blending at least one of the crude products with one or more components to produce transportation fuel.

219. The method of claim 205, further comprising:

decomposing at least some dawsonite in the portion with the provided heat;

providing a chelating agent to the portion to dissolve at least some dawsonite decomposition products; and

producing the dissolved dawsonite decomposition products.

220. The method of claim 205, wherein the temperature of the first fluid is selected to inhibit plugging of production wells in the formation during production of hydrocarbon fluids.

221. A method for treating an oil shale formation, the method comprising:

providing a first fluid to a first portion of the formation;

producing a second fluid from the first portion, wherein the second fluid includes at least some sodium bicarbonate dissolved in the first fluid;

providing heat from one or more heat sources to heat a second portion of the formation; and

using heat from the second portion of the formation to heat the second fluid to produce soda ash.

222. The method of claim 221, further comprising leaving a section of substantially impermeable material to the side of the portion to inhibit fluid flow into or out of the portion.

223. The method of claim 221, further comprising leaving a section of substantially impermeable material above the portion to inhibit fluid flow into or out of the portion.

224. The method of claim 221, further comprising forming a barrier that extends into the impermeable material.

225. The method of claim 221, wherein at least one well used to introduce the first fluid into the portion and/or to remove the second fluid from the portion is also used to remove hydrocarbon containing fluid from the portion.

226. The method of claim 221, wherein introducing the first fluid comprises introducing the first fluid through a first injection well and a second injection well, wherein the introduction of the first fluid increases the permeability of the portion adjacent to the first injection well and the second injection well, and where the increased permeability adjacent the first injection well overlaps the increased permeability adjacent the second injection well to allow introduction of the first fluid through the first injection well and removal of the second fluid through the second injection well.

227. The method of claim 221, wherein the first fluid comprises hot water.

228. The method of claim 221, wherein heat used to heat the first fluid is recovered from a previously treated portion of the formation.

229. The method of claim 221, wherein producing the second fluid from the portion causes selection vertical shifting of the portion such that the hydrocarbon richness of the portion that has been vertically shifted is increased.

230. The method of claim 221, further comprising introducing at least some of the second fluid into a second portion of the formation and producing a third fluid comprising soda ash from the second portion.

231. The method of claim 230, further comprising absorbing at least a portion of carbon dioxide generated during conversion of sodium bicarbonate to soda ash into the second portion.

232. The method of claim 221, further comprising flowing at least some of the second fluid into and out of wellbores in the formation to transfer heat to the second fluid, wherein the transferred heat converts at least a portion of the sodium bicarbonate in the second fluid to soda ash.

233. The method of claim 221, further comprising heating the portion with heat sources to a temperature above a pyrolysis temperature of hydrocarbons in the portion, and producing hydrocarbons from the portion.

234. The method of claim 233, further comprising processing at least a portion of the hydrocarbons to produce one or more crude products; and blending at least one of the crude products with one or more components to produce transportation fuel.

235. The method of claim 221, further comprising:

decomposing at least some dawsonite in the portion with the provided heat;

providing a chelating agent to the portion to dissolve at least some dawsonite decomposition products; and

producing the dissolved dawsonite decomposition products.

236. The method of claim 221, wherein the temperature of the first fluid is selected to inhibit plugging of production wells in the formation during production of hydrocarbon fluids.

237. A method for treating an oil shale formation comprising nahcolite, the method comprising:

providing a first fluid to a portion of the formation;

producing a second fluid from the portion to cause selective vertical shifting of at least some of the portion of the formation, the second fluid including at least some nahcolite dissolved in the first fluid;

providing heat from one or more heaters to the formation to heat at least a portion of the formation that has been vertically shifted; and

producing hydrocarbon fluids from the formation.

238. The method of claim 237, further comprising leaving a section of substantially impermeable material to the side of the portion to inhibit fluid flow into or out of the portion.

239. The method of claim 237, further comprising leaving a section of substantially impermeable material above the portion to inhibit fluid flow into or out of the portion.

240. The method of claim 237, further comprising forming a barrier that extends into the impermeable material.

241. The method of claim 237, wherein at least one well used to introduce the first fluid into the portion and/or to remove the second fluid from the portion is also used to remove hydrocarbon containing fluid from the portion.

242. The method of claim 237, wherein introducing the first fluid comprises introducing the first fluid through a first injection well and a second injection well, wherein the introduction of the first fluid increases the permeability of the portion adjacent to the first injection well and the second injection well, and where the increased permeability adjacent the first injection well overlaps the increased permeability adjacent the second injection well to allow introduction of the first fluid through the first injection well and removal of the second fluid through the second injection well.

243. The method of claim 237, wherein the first fluid comprises hot water.

244. The method of claim 237, wherein heat used to heat the first fluid is recovered from a previously treated portion of the formation.

245. The method of claim 237, wherein producing the second fluid from the portion causes selection vertical shifting of the portion such that the hydrocarbon richness of the portion that has been vertically shifted is increased.

246. The method of claim 237, further comprising introducing at least some of the second fluid into a second portion of the formation and producing a third fluid comprising soda ash from the second portion.

247. The method of claim 246, further comprising absorbing at least a portion of carbon dioxide generated during conversion of sodium bicarbonate to soda ash into the second portion.

248. The method of claim 237, further comprising flowing at least some of the second fluid into and out of wellbores in the formation to transfer heat to the second fluid, wherein the transferred heat converts at least a portion of the sodium bicarbonate in the second fluid to soda ash.

249. The method of claim 237, further comprising heating the portion with heat sources to a temperature above a pyrolysis temperature of hydrocarbons in the portion, and producing hydrocarbons from the portion.

250. The method of claim 249, further comprising processing at least a portion of the hydrocarbons to produce one or more crude products; and blending at least one of the crude products with one or more components to produce transportation fuel.

251. The method of claim 237, further comprising:

decomposing at least some dawsonite in the portion with the provided heat;

providing a chelating agent to the portion to dissolve at least some dawsonite decomposition products; and

producing the dissolved dawsonite decomposition products.

252. The method of claim 237, wherein the temperature of the first fluid is selected to inhibit plugging of production wells in the formation during production of hydrocarbon fluids.

253. A method for treating an oil shale formation comprising nahcolite, the method comprising:

providing a first fluid comprising steam to a portion of the formation, wherein the first fluid is at a temperature below a pyrolysis temperature of hydrocarbons in the portion of the formation;

producing a second fluid from the portion, wherein the second fluid comprises nahcolite;

providing heat from one or more heaters to the formation to heat the formation; and

producing hydrocarbon fluids from the formation.

254. The method of claim 253, further comprising leaving a section of substantially impermeable material to the side of the portion to inhibit fluid flow into or out of the portion.

255. The method of claim 253, further comprising leaving a section of substantially impermeable material above the portion to inhibit fluid flow into or out of the portion.

256. The method of claim 253, further comprising forming a barrier that extends into the impermeable material.

257. The method of claim 253, wherein at least one well used to introduce the first fluid into the portion and/or to remove the second fluid from the portion is also used to remove hydrocarbon containing fluid from the portion.

258. The method of claim 253, wherein introducing the first fluid comprises introducing the first fluid through a first injection well and a second injection well, wherein the introduction of the first fluid increases the permeability of the portion adjacent to the first injection well and the second injection well, and where the increased permeability adjacent the first injection well overlaps the increased permeability adjacent the second injection well to allow introduction of the first fluid through the first injection well and removal of the second fluid through the second injection well.

259. The method of claim 253, wherein the first fluid comprises hot water.

260. The method of claim 253, wherein heat used to heat the first fluid is recovered from a previously treated portion of the formation.

261. The method of claim 253, wherein producing the second fluid from the portion causes selection vertical shifting of the portion such that the hydrocarbon richness of the portion that has been vertically shifted is increased.

262. The method of claim 253, further comprising introducing at least some of the second fluid into a second portion of the formation and producing a third fluid comprising soda ash from the second portion.

263. The method of claim 262, further comprising absorbing at least a portion of carbon dioxide generated during conversion of sodium bicarbonate to soda ash into the second portion.

264. The method of claim 253, further comprising flowing at least some of the second fluid into and out of wellbores in the formation to transfer heat to the second fluid, wherein the transferred heat converts at least a portion of the sodium bicarbonate in the second fluid to soda ash.

265. The method of claim 253, further comprising heating the portion with heat sources to a temperature above a pyrolysis temperature of hydrocarbons in the portion, and producing hydrocarbons from the portion.

266. The method of claim 265, further comprising processing at least a portion of the hydrocarbons to produce one or more crude products; and blending at least one of the crude products with one or more components to produce transportation fuel.

267. The method of claim 253, further comprising:

decomposing at least some dawsonite in the portion with the provided heat;

providing a chelating agent to the portion to dissolve at least some dawsonite decomposition products; and

producing the dissolved dawsonite decomposition products.

268. The method of claim 253, wherein the temperature of the first fluid is selected to inhibit plugging of production wells in the formation during production of hydrocarbon fluids.

269. A method for producing one or more crude products, comprising:

producing formation fluid from a subsurface in situ heat treatment process;

separating the formation fluid to produce a liquid stream and a gas stream;

providing at least a portion of the liquid stream to a nanofiltration system to produce a retentate and a permeate, wherein the retentate comprises clogging compositions; and

processing the permeate in one or more of processing units downstream of the nanofiltration system to form one or more crude products.

270. The method of claim 269, wherein the nanofiltration system is skid mounted.

271. The method of claim 269, wherein the nanofiltration system comprises one or more nanofiltration membranes.

272. The method of claim 269, wherein the nanofiltration system comprises one or more reverse osmosis type membranes.

273. The method of claim 269, wherein the membrane comprises a top layer made of a dense membrane and a support layer made of a porous membrane.

274. The method of claim 273, wherein the dense membrane is made from a polysiloxane.

275. The method of claim 269, wherein the nanofiltration system comprises one or more spirally wound modules.

276. The method of claim 269, wherein the nanofiltration system comprises one or more spirally wound modules, and wherein at least one of the spirally wound modules comprises a polysiloxane.

277. The method of claim 269, wherein the nanofiltration system comprises one or more ceramic membranes.

278. The method of claim 269, wherein the liquid stream has at most 10% by weight water.

279. The method of claim 269, wherein the liquid stream is provided to the nanofiltration system continuously for at least 10 hours without cleaning a feed side of a membrane of the nanofiltration system.

280. The method of claim 269, wherein a final boiling point of the permeate is less than the final boiling point of the liquid stream, wherein boiling points are determined by ASTM Method D5307.

281. The method of claim 269, wherein at least one of the processing units comprises a hydrotreating unit.

282. The method of claim 269, wherein at least one of the processing units comprises a selective hydrogenation unit.

283. The method of claim 269, wherein at least one of the processing units comprises a hydrotreating unit and the method further comprises contacting the permeate with one or more catalysts in the presence of hydrogen to produce a product suitable for transportation and/or refinery use.

284. The method of claim 269, wherein the in situ heat treatment process comprises heating a hydrocarbon containing formation with one or more heat sources.

285. The method of claim 269, wherein the formation fluid comprises mobilized fluids, visbroken fluids, pyrolyzed fluids, or mixtures thereof.

286. The method of claim 269, further comprising providing at least a portion of the retentate to a delayed coking unit and/or a gasification unit.

287. The method of claim 269, further comprising blending one or more of the crude products with other components to produce gasoline.

288. The method of claim 269, further comprising blending at least one of the crude products with other components to produce gasoline.

289. The method of claim 269, further comprising blending at least one of the crude products with other components to produce transportation fuel.

290. A system for treating an in situ heat treatment fluid, comprising:

a production well located in a formation, the production well configured to produce a formation fluid, wherein the formation fluid is produced using an in situ heat treatment process;

a separation unit, the separation unit configured receive the formation fluid from the production well and the separation unit configured to separate the formation fluid into a liquid stream and a gas stream;

a nanofiltration system configured to receive the liquid stream and the nanofiltration system configured to separate the liquid stream into a retentate and a permeate.

291. The system of claim 290, wherein the nanofiltration system is skid mounted.

292. The system of claim 290, wherein the nanofiltration system comprises one or more nanofiltration membranes.

293. The system of claim 290, wherein the nanofiltration system comprises one or more reverse osmosis type membranes.

294. The system of claim 290, wherein the membrane comprises a top layer made of a dense membrane and a support layer made of a porous membrane.

295. The system of claim 294, wherein the dense membrane is made from a polysiloxane.

296. The system of claim 290, wherein the nanofiltration system comprises one or more spirally wound modules.

297. The system of claim 290, wherein the nanofiltration system comprises one or more spirally wound modules, and wherein at least one of the spirally wound modules comprises a polysiloxane.

298. The system of claim 290, wherein the nanofiltration system comprises one or more ceramic membranes.

299. A method, comprising:

producing formation fluid from a subsurface in situ heat treatment process;

separating the formation fluid to produce a liquid stream and a gas stream;

providing at least a portion of the liquid stream to a hydrotreating unit; and

removing of at least a portion of selected in situ heat treatment clogging compositions in the liquid stream to produce a hydrotreated liquid stream by hydrotreating at least a portion of the liquid stream at conditions sufficient to remove the selected in situ heat treatment clogging compositions.

300. The method of claim 299, wherein one or more of the clogging compositions comprise solids produced as a result of the in situ heat treatment process.

301. The method of claim 299, wherein one or more of the clogging compositions comprise a mixture of solids and hydrocarbons produced from the in situ heat treatment process.

302. The method of claim 299, wherein one or more of the clogging compositions comprise olefins and solids produced from the in situ heat treatment process.

303. The method of claim 299, wherein the clogging compositions comprise pyrolyzation products produced from in situ pyrolyzation of hydrocarbons.

304. The method of claim 299, wherein the clogging compositions are di-olefins and hydrotreating converts at least a portion of the di-olefins to mono-olefins.

305. The method of claim 299, wherein hydrotreating comprises contacting the liquid stream with one or more catalysts in the presence of hydrogen to produce a product suitable for transportation and/or refinery use.

306. The method of claim 299, wherein the in situ heat treatment process comprises heating a hydrocarbon containing formation with one or more heat sources.

307. The method of claim 299, wherein the formation fluid comprises mobilized fluids, visbroken fluids, pyrolyzed fluids, or mixtures thereof.

308. The method of claim 299, further comprising processing at least a portion of the hydrotreated liquid stream in one or more of the downstream processing units to form one or more crude products.

309. The method of claim 308, wherein at least one of the processing units comprises a fractionation unit.

310. The method of claim 308, wherein at least one of the crude products is a liquid mixture at 25 °C and 0.101 MPa.

311. The method of claim 308, wherein at least one of the crude products is a gaseous mixture at 25 °C and 0.101 MPa.

312. The method of claim 308, wherein at least one of the crude products is a gaseous mixture at 25 °C and 0.101 MPa, and wherein the gaseous mixture comprises hydrocarbons having a carbon number of at least 3.

313. The method of claim 308, wherein at least one of the crude products comprises diesel.

314. The method of claim 308, wherein at least one of the crude products comprises naphtha.

315. The method of claim 308, wherein at least one of the crude products comprises vacuum gas oil.

316. The method of claim 308, wherein at least a portion of one of the crude products is blended with a formation fluid produced from an in situ heat treatment process.

317. The method of claim 308, wherein the formation comprises oil shale, and wherein at least one of the crude products is blended with a heavy oil/tar sands fluid produced by an in situ heat treatment process.

318. The method of claim 308, further comprising blending at least one of the crude products with other components to produce gasoline.

319. The method of claim 308, further comprising blending at least one of the crude products with other components to produce transportation fuel.

320. A transportation fuel, wherein the transportation fuel is made by a method comprising:

producing formation fluid from a subsurface in situ heat treatment process;

separating the formation fluid to produce a liquid stream and a gas stream;

providing at least a portion of the liquid stream to a hydrotreating unit;

removing of at least a portion of selected in situ heat treatment clogging compositions in the liquid stream to produce a hydrotreated liquid stream by hydrotreating at least a portion of the liquid stream at conditions sufficient to remove the selected in situ heat treatment clogging compositions; and

blending one or more of the crude products with other components to make transportation fuel.

321. A method for producing alkylated hydrocarbons, comprising:

producing formation fluid from a subsurface in situ heat treatment process;

separating the formation fluid to produce a liquid stream and a first gas stream, wherein the first gas stream comprises olefins;

fractionating the liquid stream to produce at least a second gas stream comprising hydrocarbons having a carbon number of at least 3; and

introducing the first gas stream and the second gas stream into an alkylation unit to produce alkylated hydrocarbons, wherein at least a portion of the olefins in the first gas stream enhance alkylation.

322. The method of claim 321, wherein the olefins in the first gas stream comprise hydrocarbons having a carbon number of at least 3.

323. The method of claim 321, wherein the olefins in the first and second gas streams comprise propylene, butylenes, amylenes, or combinations thereof.

324. The method of claim 321, wherein the alkylated hydrocarbons comprise hydrocarbons having a carbon number of at least 4.

325. The method of claim 321, wherein the alkylated hydrocarbons comprise butanes, pentanes, hexanes, heptanes, or mixtures thereof.

326. The method of claim 321, wherein fractionating the liquid stream produces a hydrocarbon stream comprising hydrocarbons having a carbon number of at least 5.

327. The method of claim 321, wherein fractionating the liquid stream produces a hydrocarbon stream comprising hydrocarbons having a carbon number of at least 5, and further comprising providing at least a portion of the hydrocarbon stream to the alkylation unit.

328. The method of claim 321, wherein fractionating the liquid stream produces a hydrocarbon stream having an initial boiling point of at least 343 °C as determined by ASTM Method D2887.

329. The method of claim 321, wherein fractionating the liquid stream produces a hydrocarbon stream having an initial boiling point of at least 343 °C as determined by ASTM Method D2887 and the method further comprising:

catalytically cracking the bottoms stream to produce a hydrocarbon stream comprising hydrocarbons having a carbon number from 3 to 5; and

providing at least a portion of the C3-C5 hydrocarbon stream to the alkylation unit.

330. The method of claim 321, wherein fractionating the liquid stream produces naphtha, and the method further comprises blending the naphtha with formation fluid to produce a blended fluid.

331. The method of claim 321, further comprising blending at least a portion of the alkylated hydrocarbons with other components to produce gasoline.

332. The method of claim 321, further comprising blending at least a portion of the alkylated hydrocarbons with other components to produce transportation fuel.

333. A method of producing alkylated hydrocarbons, comprising:

producing formation fluid from a subsurface in situ heat treatment process;

separating the formation fluid to produce a liquid stream;

catalytically cracking at least a portion of the liquid stream in a first catalytic cracking system to produce a crude product;

separating at least a portion of the crude product into one or more hydrocarbon streams, wherein at least one of the hydrocarbon streams is a gasoline hydrocarbons stream;

catalytically cracking at least a portion of the gasoline hydrocarbons stream by contacting the gasoline hydrocarbon stream with a catalytic cracking catalyst in a second catalytic cracking system to produce a crude olefin stream; and

introducing at least a portion of the crude olefin stream into an alkylation unit to produce one or more alkylated hydrocarbons.

334. The method of claim 333, wherein the olefin stream comprises hydrocarbons having a carbon number from 3 to 5.

335. The method of claim 333, wherein the olefin stream comprises ethylene, propylene, butenes, isobutylenes, or mixtures thereof.

336. The method of claim 333, wherein the olefin stream comprise at least 50% by weight olefins having a carbon number of at most 5.

337. The method of claim 333, wherein catalytically cracking at least a portion of the liquid stream produces a gas stream, wherein the gas stream comprises hydrocarbons having a carbon number of at least 3.

338. The method of claim 333, wherein catalytically cracking at least a portion of the gasoline hydrocarbons stream produces a used catalytic cracking catalyst stream and the method further comprises providing the used catalytic cracking catalyst stream to the first catalytic cracking system.

339. The method of claim 333, further comprising providing a hydrocarbon stream having an initial boiling point above 343 °C to the second catalytic cracking system, wherein the boiling point is determined by ASTM Method D2887.

340. The method of claim 333, further comprising hydrotreating at least a portion of the liquid stream at conditions sufficient for removal of clogging compositions.

341. The method of claim 333, further comprising blending at least a portion of the alkylated hydrocarbons with other components to produce gasoline.

342. The method of claim 333, further comprising blending at least a portion of the alkylated hydrocarbons with other components to produce transportation fuel.

343. A transportation fuel, wherein the transportation fuel is made by a method comprising:

producing formation fluid from a subsurface in situ heat treatment process;

separating the formation fluid to produce a liquid stream and a first gas stream, wherein the first gas stream comprises olefins;

fractionating the liquid stream to produce at least a second gas stream comprising hydrocarbons having a carbon number of at least 3,

introducing the first gas stream and the second gas stream into an alkylation unit to produce alkylated hydrocarbons, wherein the olefins in the first gas stream enhance alkylation;

blending at least a portion of the alkylated hydrocarbons with one or more components to produce the transportation fuel.

344. A method for producing a crude product, comprising:

producing formation fluid from a subsurface in situ heat treatment process;

separating the formation fluid to produce a liquid stream and a first gas stream, wherein the first gas stream comprises olefins;

fractionating the liquid stream to produce one or more crude products, wherein at least one of the crude products has a boiling range distribution from 38 °C and 343 °C as determined by ASTM Method D5307; and

catalytically cracking the crude product having the boiling range distribution from 38 °C and 343 °C to produce one or more additional crude products, wherein at least one of the additional crude products is a second gas stream, and the second gas stream has a boiling point of at most 38 °C at 0.101 MPa.

345. The method of claim 344, wherein the second gas stream comprises hydrocarbons having a carbon number of at least 2.

346. The method of claim 344, wherein the in situ heat treatment process causes pyrolyzation of at least some hydrocarbons in the formation.

347. The method of claim 344, wherein at least one of the additional crude products has a boiling range distribution between 38 °C and 200 °C as determined by ASTM Method D5307.

348. The method of claim 344, wherein the second gas stream comprises olefins having a carbon number from 3 to 5 and further comprising providing at least a portion of the olefins to an alkylation unit, and then alkylating the olefins to produce hydrocarbons suitable for blending to produce transportation fuel.

349. The method of claim 348, wherein the transportation fuel is gasoline.

350. The method of claim 348, further comprising providing at least a portion of the olefins to a polymerization unit.

351. The method of claim 348, further comprising hydrotreating at least a portion of the liquid stream at conditions sufficient for removal of clogging compositions.

352. A method for producing hydrocarbons, comprising:

producing formation fluid from a subsurface in situ heat treatment process;

separating the formation fluid to produce a liquid stream;

catalytically cracking the liquid stream in a first catalytic cracking system by contacting the liquid stream with a catalytic cracking catalyst to produce a crude product stream and a spent catalytic cracking catalyst;

regenerating the spent catalytic cracking catalyst to produce a regenerated cracking catalyst;

catalytically cracking a gasoline hydrocarbons stream in a second catalytic cracking system by contacting the gasoline hydrocarbons stream with the regenerated catalytic cracking catalyst to produce a crude olefin stream comprising hydrocarbons having a carbon number of at least 2 and a used regenerated cracking catalyst;

separating at least some olefins from the crude olefin stream, wherein the olefins have a carbon number from 2 to 5; and

providing the used regenerated cracking catalyst from the second catalytic cracking system to the first catalytic cracking system.

353. The method of claim 352, wherein the catalytic cracking catalyst comprises amorphous silica alumina and a zeolite.

354. The method of claim 352, further comprising providing ZSM-5 to the second catalytically cracking system.

355. The method of claim 352, wherein a coke content of the regenerated catalytic cracking catalyst ranges from 0.01% by weight to 0.5% by weight.

356. The method of claim 352, wherein a weight ratio of the used regenerated cracking catalyst to the regenerated cracking catalyst ranges from 0.1:1 to 100:1.

357. The method of claim 352, further comprising providing steam to the first and/or second catalytic cracking systems.

358. The method of claim 352, further comprising separating the crude product into one or more hydrocarbon streams, wherein at least one of the hydrocarbons stream is a gasoline hydrocarbons stream; and providing at least a portion of the gasoline hydrocarbons stream to the second catalytic cracking system.

359. The method of claim 352, wherein at least one of the hydrocarbons stream is a cycle oil stream; and providing at least a portion of the cycle oil stream to the first catalytic cracking system.

360. The method of claim 352, further comprising providing at least a portion of the olefins having a carbon number from 3 to 5 to an alkylation unit.

361. The method of claim 352, further comprising providing at least a portion of the olefins having a carbon number from 3 to 5 to an alkylation unit, and then alkylating the olefins to produce hydrocarbons suitable for blending to produce transportation fuel.

362. The method of claim 361, wherein the transportation fuel is gasoline.

363. The method of claim 352, further comprising providing at least a portion of the olefins to a polymerization unit.

364. The method of claim 352, further comprising hydrotreating at least a portion of the liquid stream at conditions sufficient for removal of clogging compositions.

365. A transportation fuel, wherein the transportation fuel is made by a method comprising:

producing formation fluid from a subsurface in situ heat treatment process;

separating the formation fluid to produce a liquid stream and a first gas stream, wherein the first gas stream comprises olefins;

fractionating the liquid stream to produce one or more crude products, wherein at least one of the crude products has a boiling range distribution from 38 °C and 343 °C;

catalytically cracking the crude product at least one of the crude products having a boiling range distribution from 38 °C and 343 °C to produce one or more additional crude products, wherein least one of the additional crude products is a second gas stream, wherein the second gas stream comprises olefins having a carbon number from 3 to 5;

alkylating at least some of the olefins to produce hydrocarbons; and

blending at least a portion of the hydrocarbons with one or more components to produce transportation fuel, wherein boiling range distributions are determined by ASTM Method D5307.

366. A system for treating a tar sands formation, comprising:

a plurality of heaters located in the formation, wherein the heaters include at least partially horizontal heating sections at least partially in a hydrocarbon layer of the formation, the heating sections being at least partially arranged in a pattern in the hydrocarbon layer, and the heaters being configured to provide heat to the hydrocarbon layer, the provided heat creating a plurality of drainage paths for mobilized fluids, at least two of the drainage paths converging; and

a production well located to collect and produce mobilized fluids from at least one of the converged drainage paths in the hydrocarbon layer.

367. The system of claim 366, wherein heat from the heaters is configured to at least partially superimpose over the production well to create a path for at least some of the mobilized fluids to flow to the production well.

368. The system of claim 366, wherein the production well is located such that at least some of the fluids in the formation drain towards the production well.

369. The system of claim 366, wherein the production well includes a heater to provide heat to the production well and at least a portion of the formation surrounding the production well.

370. The system of claim 366, wherein the production well is configured to produce at least some pyrolyzed fluids from the formation.

371. The system of claim 366, wherein the system further comprises a pump in the production well to remove fluids from the formation.

372. The system of claim 366, wherein the heaters are elongated heaters.

373. The system of claim 366, wherein the pattern includes heating sections with substantially equidistant spacing between the heating sections in the pattern.

374. The system of claim 366, wherein the pattern is a triangular pattern of heating sections.

375. The system of claim 366, wherein the system further comprises a steam source configured to provide steam to the formation.

376. The system of claim 366, wherein the pattern of heating sections includes a vertex oriented towards the bottom of the hydrocarbon layer.

377. The system of claim 376, wherein the production well is located near or below the vertex that is oriented towards the bottom of the hydrocarbon layer.

378. The system of claim 366, wherein the production well is located such that heat from at least one of the heaters heats at least a portion of the hydrocarbon layer proximate the production well.

379. The system of claim 366, wherein the production well is located a distance from the nearest heater that is no more than the average spacing between heaters in the pattern.

380. The system of claim 366, wherein the heaters are configured to provide heat such that drainage paths are created by creating more permeable zones in the formation.

381. The system of claim 366, wherein the production well is located between 2 m and 10 m from the nearest heater.

382. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation, wherein the heaters include at least partially horizontal heating sections at least partially in a hydrocarbon layer of the formation, the heating sections being at

least partially arranged in a pattern in the hydrocarbon layer, and the heaters being configured to provide heat to the hydrocarbon layer;

wherein the provided heat creates a plurality of drainage paths for mobilized fluids, at least two of the drainage paths converging;

allowing at least some of the mobilized fluids from the formation to flow to the production well along at least one of the converged drainage paths; and

producing at least some of the mobilized fluids through the production well.

383. The method of claim 382, further comprising providing heat to the hydrocarbon layer from the heaters such that the heat at least partially superimposes over the production well to create a path for the flow of at least some of the mobilized fluids to the production well.

384. The method of claim 382, further comprising allowing fluids in the hydrocarbon layer to drain to the production well along the drainage paths and/or the converged drainage paths.

385. The method of claim 382, further comprising providing heat in the production well to provide heat to the production well and at least a portion of the formation surrounding the production well.

386. The method of claim 382, further comprising producing at least some pyrolyzed fluids from the formation.

387. The method of claim 382, further comprising pumping fluids to the surface of the formation.

388. The method of claim 382, further comprising providing the fluids to one or more processing units, processing the fluids to produce one or more crude products; and making transportation fuel from one or more of the crude products.

389. The method of claim 382, further comprising providing steam to the formation.

390. The method of claim 382, further comprising providing heat such that the drainage paths are created by creating more permeable zones in the formation.

391. A transportation fuel produced by a method comprising:

providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation, wherein the heaters include at least partially horizontal heating sections at least partially in a hydrocarbon layer of the formation, the heating sections being at least partially arranged in a pattern in the hydrocarbon layer, and the heaters being configured to provide heat to the hydrocarbon layer;

wherein the provided heat creates a plurality of drainage paths for mobilized fluids, at least two of the drainage paths converging;

allowing at least some of the mobilized fluids from the formation to flow to the production well along at least one of the converged drainage paths;

producing at least some of the mobilized fluids through the production well; and

processing at least some of the mobilized fluids to produce the transportation fuel.

392. A system for treating a hydrocarbon containing formation, comprising:

a steam and electricity cogeneration facility;

at least one injection well located in a first portion of the formation, the injection well configured to provide steam from the steam and electricity cogeneration facility to the first portion of the formation;

at least one production well located in the first portion of the formation, the production well configured to produce first hydrocarbons;

at least one electrical heater located in a second portion of the formation, at least one of the electrical heaters configured to be powered by electricity from the steam and electricity cogeneration facility;

at least one production well located in the second portion of the formation, the production well configured to produce second hydrocarbons; and

the steam and electricity cogeneration facility configured to use the first hydrocarbons and/or the second hydrocarbons to generate electricity.

393. The system of claim 392, wherein the facility is configured to use the first and/or second hydrocarbons to make electricity in one or more generators, and exhaust heat from at least one of the generators is configured to be used to make steam.

394. The system of claim 392, wherein the facility is configured to use hydrocarbons to make steam.

395. The system of claim 392, wherein the first hydrocarbons have an API gravity at most about 15°.

396. The system of claim 392, wherein the second hydrocarbons have an API gravity of at least about 20°.

397. The system of claim 392, wherein the system is configured to mix at least a portion of the first hydrocarbons and at least a portion of the second hydrocarbons.

398. The system of claim 392, wherein the system is configured to vary the amount of electricity generated and the amount of steam made to vary the production of the first hydrocarbons and/or the second hydrocarbons.

399. The system of claim 392, wherein the system further comprises a treatment facility for treating the first hydrocarbons and/or second hydrocarbons before use in the steam and electricity cogeneration facility.

400. The system of claim 392, wherein the steam and electricity cogeneration facility is configured to burn both gaseous and liquid hydrocarbons.

401. The system of claim 392, wherein the first and second portions are separated from each other by a barrier or by a substantially impermeable zone of the formation.

402. The system of claim 392, wherein the formation comprises different layers at different depths.

403. The system of claim 392, wherein the first portion is at a depth that is different from the second portion, and wherein the first portion comprises different initial hydrocarbon properties than the second portion.

404. A method for treating a hydrocarbon containing formation, comprising:

providing steam to a first portion of the formation;

producing first hydrocarbons from the first portion of the formation;

providing heat from one or more electrical heaters to a second portion of the formation;

allowing the provided heat to transfer from the heaters to the second portion of the formation;

producing second hydrocarbons from the second portion of the formation; and

using the first hydrocarbons and/or the second hydrocarbons in a steam and electricity generation facility, wherein the facility provides steam to the first portion of the formation and electricity for at least some of the heaters.

405. The method of claim 404, further comprising using the first hydrocarbons and/or the second hydrocarbons to make electricity in one or more generators, and using exhaust from at least one of the generators to make steam.

406. The method of claim 404, further comprising burning the first hydrocarbons and/or the second hydrocarbons to make steam.

407. The method of claim 404, wherein the first hydrocarbons have an API gravity at most about 15°.

408. The method of claim 404, wherein the second hydrocarbons have an API gravity of at least about 20°.

409. The method of claim 404, further comprising mixing at least a portion of the first hydrocarbons and at least a portion of the second hydrocarbons.

410. The method of claim 404, further comprising mixing at least a portion of the first hydrocarbons and at least a portion of the second hydrocarbons to make a fuel for electrical generators.

411. The method of claim 404, further comprising using at least a portion of the second hydrocarbons as a gas for one or more heaters in the formation.

412. The method of claim 404, further comprising using all of the first hydrocarbons and/or the second hydrocarbons as fuel for generating electricity and/or to make steam.

413. The method of claim 404, further comprising varying the amount of electricity generated and the amount of steam made to vary the production of the first hydrocarbons and/or the second hydrocarbons.

414. The method of claim 404, further comprising providing steam to the second portion prior to providing heat from the electrical heaters.

415. The method of claim 404, further comprising producing a transportation fuel from at least some of the first and/or the second hydrocarbons.

416. A method for treating a hydrocarbon containing formation, comprising:

providing steam to a first portion of the formation;

providing heat from one or more electrical heaters to the first portion of the formation;

producing first hydrocarbons and/or second hydrocarbons from the first portion of the formation;

providing heat from one or more electrical heaters to a second portion of the formation;

allowing the provided heat to transfer from the heaters to the second portion of the formation;

producing second hydrocarbons from the second portion of the formation; and

using the first hydrocarbons and/or the second hydrocarbons in a steam and electricity generation facility, wherein the facility provides steam to the first portion of the formation and electricity for at least some of the heaters.

417. The method of claim 416, further comprising using the first hydrocarbons and/or the second hydrocarbons to make electricity.

418. The method of claim 416, further comprising using the first hydrocarbons and/or the second hydrocarbons to make steam.

419. The method of claim 416, wherein the first hydrocarbons have an API gravity at most about 15°.

420. The method of claim 416, wherein the second hydrocarbons have an API gravity of at least about 20°.

421. The method of claim 416, further comprising varying the amount of electricity generated and the amount of steam made to vary the production of the first hydrocarbons and/or the second hydrocarbons.

422. The method of claim 416, further comprising allowing heat and/or hydrocarbons to transfer between the first and the second portions.

423. The method of claim 416, further comprising producing a transportation fuel from at least some of the first and/or the second hydrocarbons.

424. A method for treating a hydrocarbon containing formation, comprising:

providing steam to a first portion of the formation;

producing first hydrocarbons from the first portion of the formation;

providing heat from one or more electrical heaters to a second portion of the formation;

allowing the provided heat to transfer from the heaters to the second portion of the formation;

providing steam to the second portion of the formation;

producing first hydrocarbons and/or second hydrocarbons from the second portion of the formation; and

using the first hydrocarbons and/or the second hydrocarbons in a steam and electricity generation facility, wherein the facility provides steam to the first portion or the second portion of the formation and electricity for at least some of the heaters.

425. The method of claim 424, further comprising using the first hydrocarbons and/or the second hydrocarbons to make electricity.

426. The method of claim 424, further comprising using the first hydrocarbons and/or the second hydrocarbons to make steam.

427. The method of claim 424, wherein the first hydrocarbons have an API gravity at most about 15°.

428. The method of claim 424, wherein the second hydrocarbons have an API gravity of at least about 20°.

429. The method of claim 424, further comprising providing heat from one or more electrical heaters to the first portion of the formation, and producing first hydrocarbons and/or second hydrocarbons from the first portion of the formation.

430. The method of claim 424, further comprising varying the amount of electricity generated and the amount of steam made to vary the production of the first hydrocarbons and/or the second hydrocarbons.

431. The method of claim 424, further comprising allowing heat and/or hydrocarbons to transfer between the first and the second portions.

432. The method of claim 424, further comprising producing a transportation fuel from at least some of the first and/or the second hydrocarbons.

433. A method for treating an oil shale formation comprising dawsonite, the method comprising:

providing heat from one or more heaters to the formation to heat the formation;

producing hydrocarbon fluids from the formation;

decomposing at least some dawsonite in the formation with the provided heat;

providing a chelating agent to the formation to dissolve at least some dawsonite decomposition products; and

producing the dissolved dawsonite decomposition products.

434. The method of claim 433, further comprising:

providing a first fluid to a portion of the formation comprising nahcolite; and

producing a second fluid from the portion, the second fluid including at least some nahcolite dissolved in the first fluid.

435. The method of claim 433, wherein the dissolved decomposition products comprise alumina.

436. The method of claim 433, wherein the chelating agent is an aqueous acid.

437. The method of claim 433, wherein the chelating agent is EDTA.

438. The method of claim 433, further comprising providing the chelating agent through one or more injection wells in the formation.

439. The method of claim 433, further comprising providing the chelating agent through one or more production wells in the formation.

440. The method of claim 433, further comprising providing the chelating agent through one or more heater wells in the formation.

441. The method of claim 433, further comprising separating the chelating agent from the dissolved decomposition products in a treatment facility.

442. The method of claim 441, further comprising recovering chelating agent from the dissolved decomposition products, and recycling the recovered chelating agent back into the formation to dissolve dawsonite decomposition products.

443. The method of claim 433, further comprising:

providing a relatively basic fluid to the formation to dissolve at least some dawsonite decomposition products; and

producing the dissolved dawsonite decomposition products.

444. The method of claim 433, further comprising:

assessing a dawsonite composition of one or more zones in the formation; and

providing heat from one or more heaters to the formation such that different amounts of heat are provided to zones with different dawsonite compositions.

445. The method of claim 444, further comprising providing more heat from heaters in or proximate zones with dawsonite than from heaters in or proximate zones with little or no dawsonite.

446. The method of claim 433, further comprising producing aluminum metal from the dissolved decomposition products in a process that utilizes electricity that has been generated using hydrocarbons produced from the formation.

447. A method for treating an oil shale formation comprising dawsonite, the method comprising:

providing heat from one or more heaters to the formation to heat the formation;

producing hydrocarbon fluids from the formation;

decomposing at least some dawsonite in the formation with the provided heat;

providing a relatively basic fluid to the formation to dissolve at least some dawsonite decomposition products; and

producing the dissolved dawsonite decomposition products.

448. The method of claim 447, further comprising providing the relatively basic fluid through one or more injection wells in the formation.

449. The method of claim 447, further comprising providing the relatively basic fluid through one or more production wells in the formation.

450. The method of claim 447, further comprising providing the relatively basic fluid through one or more heater wells in the formation.

451. The method of claim 447, further comprising separating the relatively basic fluid from the dissolved decomposition products in a treatment facility.

452. The method of claim 451, further comprising recovering relatively basic fluid from the dissolved decomposition products, and recycling the recovered relatively basic fluid back into the formation to dissolve dawsonite decomposition products.

453. The method of claim 447, wherein the relatively basic fluid comprises sodium carbonate brine.

454. A method for producing aluminum, the method comprising:

providing heat from one or more heaters to an oil shale formation to heat the formation;

producing hydrocarbon fluids from the formation;

decomposing at least some dawsonite in the formation with the provided heat;

providing a chelating agent to the formation to dissolve at least some dawsonite decomposition products;

producing the dissolved dawsonite decomposition products from the formation;

separating alumina from the dissolved dawsonite decomposition products;

using some of the produced hydrocarbon fluids to produce electricity; and

producing aluminum metal from the alumina in a Hall process using the produced electricity as power for the Hall process.

455. A method for treating an oil shale formation comprising dawsonite, the method comprising:

assessing a dawsonite composition of one or more zones in the formation;

providing heat from one or more heaters to the formation such that different amounts of heat are provided to zones with different dawsonite compositions;

allowing the provided heat to transfer from the heaters to the formation; and

producing fluids from the formation.

456. The method of claim 455, further comprising providing more heat from heaters in or proximate zones with more dawsonite than from heaters in or proximate zones with less dawsonite.

457. The method of claim 455, further comprising providing more heat from heaters in or proximate zones with dawsonite than from heaters in or proximate zones with little or no dawsonite.

458. The method of claim 455, further comprising adjusting the heat output along a length of one or more heaters to provide the different amounts of heat.

459. The method of claim 455, wherein at least one heater is a temperature limited heater, the method further comprising varying the Curie temperature of the temperature limited heater along a length of the heater to provide different amounts of heat.

460. The method of claim 455, further comprising coring the formation to obtain a sample of the formation for assessment of the dawsonite composition.

461. The method of claim 455, further comprising:

providing a first fluid to a portion of the formation comprising nahcolite; and

producing a second fluid from the portion, the second fluid including at least some nahcolite dissolved in the first fluid.

462. The method of claim 455, further comprising:

providing a chelating agent to the formation to dissolve at least some dawsonite decomposition products in the formation; and

producing the dissolved dawsonite decomposition products.

463. The method of claim 462, wherein the dissolved decomposition products comprise alumina.

464. The method of claim 462, wherein the chelating agent is an aqueous acid.

465. The method of claim 462, wherein the chelating agent is EDTA.

466. The method of claim 462, further comprising separating the chelating agent from the dissolved decomposition products in a treatment facility.

467. The method of claim 462, further comprising:

providing a relatively basic fluid to the formation to dissolve at least some dawsonite decomposition products; and

producing the dissolved dawsonite decomposition products.

468. The method of claim 462, further comprising producing aluminum metal from the dissolved decomposition products in a process that utilizes electricity that has been generated using hydrocarbons produced from the formation.

469. A method for producing aluminum, the method comprising:

assessing a dawsonite composition of one or more zones in the formation;

providing heat from one or more heaters to the formation such that different amounts of heat are provided to zones with different dawsonite compositions;

allowing the provided heat to transfer from the heaters to the formation;

producing hydrocarbons from the formation;

decomposing at least some dawsonite in the formation with the provided heat;

providing a chelating agent to the formation to dissolve at least some dawsonite decomposition products;

producing the dissolved dawsonite decomposition products from the formation;

separating alumina from the dissolved dawsonite decomposition products;

using some of the produced hydrocarbon fluids to produce electricity; and

producing aluminum metal from the alumina in a Hall process using the produced electricity as power for the Hall process.

470. A method for treating an oil shale formation comprising nahcolite, the method comprising:

providing a first fluid to a portion of the formation;

producing a second fluid from the portion, wherein the second fluid includes at least some nahcolite dissolved in the first fluid;

providing a controlled amount of oxidant to the portion of the formation; and

producing hydrocarbon fluids from the formation.

471. The method of claim 470, wherein the first fluid is hot water.

472. The method of claim 470, wherein the first fluid is steam.

473. The method of claim 470, wherein the first fluid is hot water with a temperature below about 250 °C.

474. The method of claim 470, wherein the first fluid is hot water or steam pressurized to a pressure below the fracture pressure of the formation.

475. The method of claim 470, wherein the second fluid also includes carbon dioxide produced from dissolution of the nahcolite.

476. The method of claim 470, further comprising creating interconnectivity between at least two wellbores.

477. The method of claim 470, further comprising creating interconnectivity between at least two wellbores, and then providing the oxidant in such interconnectivity.

478. The method of claim 470, wherein producing nahcolite from the formation creates a permeable zone; and providing the oxidant to the permeable zone.

479. The method of claim 470, further comprising burning at least a portion of hydrocarbons in the formation with the oxidant, wherein burning of the hydrocarbons provides heat to at least a portion of the formation.

480. The method of claim 470, further comprising heating the first fluid before providing the first fluid to the formation.

481. The method of claim 470, further comprising providing the first fluid through one or more injection wells.

482. The method of claim 470, further comprising providing heat from one or more heaters to the formation to heat at least a portion of the formation.

483. The method of claim 470, further comprising providing heat from one or more heaters to the formation to heat at least a portion of the formation prior to providing the oxidant to the portion of the formation.

484. The method of claim 470, further comprising providing heat from one or more heaters to a wellbore region to facilitate oxidation, and wherein heat from such oxidation heats at least a portion of the formation.

485. The method of claim 470, further comprising providing the oxidant through one or more injection wells.

486. The method of claim 470, further comprising:

decomposing at least some dawsonite in the formation with heat;

providing a chelating agent to the formation to dissolve at least some dawsonite decomposition products; and

producing the dissolved dawsonite decomposition products.

487. The method of claim 470, further comprising:

decomposing at least some dawsonite in the formation with heat;

providing a relatively basic fluid to the formation to dissolve at least some dawsonite decomposition products; and

producing the dissolved dawsonite decomposition products.

488. The method of claim 470, further comprising controlling heating of the formation by controlling the amount of oxidant provided.

489. A method for treating an oil shale formation comprising nahcolite, the method comprising:

forming and maintaining a low temperature zone around at least a portion of a subsurface treatment area;

providing a first fluid to a portion of the subsurface treatment area;

producing a second fluid from the portion, wherein the second fluid includes at least some nahcolite dissolved in the first fluid;

providing heat from one or more heaters to the subsurface treatment area to heat the subsurface treatment area;

providing a controlled amount of oxidant to a portion of the subsurface treatment area; and

producing hydrocarbon fluids from the subsurface treatment area.

490. The method of claim 489, wherein forming and maintaining the low temperature zone comprises:

reducing a temperature of heat transfer fluid with a refrigeration system;

circulating the heat transfer fluid through freeze wells located in a subsurface formation around at least a portion of the subsurface treatment area; and

returning the heat transfer fluid to the refrigeration system.

491. The method of claim 489, further comprising controlling heating of the formation by controlling the amount of oxidant provided.

492. A method for treating an oil shale formation comprising nahcolite, the method comprising:

forming a barrier around at least a portion of a subsurface treatment area, the barrier configured to inhibit fluid from exiting or entering the subsurface treatment area;

providing a first fluid to a portion of the subsurface treatment area;

producing a second fluid from the portion, wherein the second fluid includes at least some nahcolite dissolved in the first fluid;

providing heat from one or more heaters to the subsurface treatment area to heat the subsurface treatment area;

providing a controlled amount of oxidant to a portion of the subsurface treatment area; and

producing hydrocarbon fluids from the subsurface treatment area.

493. The method of claim 492, wherein the barrier is a freeze barrier established by freeze wells.

494. The method of claim 492, wherein the barrier is a sulfur barrier.

495. The method of claim 492, wherein the barrier is a wax barrier.

496. The method of claim 492, further comprising controlling heating of the formation by controlling the amount of oxidant provided.

497. A system for heating a hydrocarbon containing formation, comprising:

a heater comprising an elongated ferromagnetic metal heater section, wherein the heater is located in an opening in a formation, the heater section being configured to heat the hydrocarbon containing formation, and the elongated ferromagnetic metal having a sulfidation rate that goes down with increasing temperature of the heater, when the heater is in a selected temperature range.

498. The system of claim 497, wherein at least a portion of the heater section is exposed to the formation.

499. The system of claim 497, wherein the heater section is 410 stainless steel.

500. The system of claim 497, wherein the heater section comprises iron, chromium, and cobalt, and wherein the weight percentage of cobalt is at least about 2% and the weight percentage of chromium is at least about 9%.

501. The system of claim 497, wherein the heater section is substantially inert to galvanic corrosion.

502. The system of claim 497, wherein the heater is a temperature limited heater.

503. The system of claim 497, wherein the heater section is substantially the only electrical path in the heater configured to carry current into and out of the formation.

504. The system of claim 497, wherein the composition of the heater section is such that sulfidation rate of the heater section decreases with increasing temperature of the heater when the heaters is at a temperature ranging between about 530 °C and about 650 °C.

505. The system of claim 497, wherein the heater section comprises at least 2.0% cobalt by weight.

506. The system of claim 497, wherein the heater section comprises at most 10% by weight cobalt.

507. The system of claim 497, wherein the heater section is an electrical resistance heater section.

508. A heater comprising a metal section comprising:

ferromagnetic stainless steel having at least 2.0% cobalt by weight; and

wherein the composition of the exposed metal section is such that the sulfidation rate of the metal section is at most about 25 mils per year at a temperature between about 800 °C and about 880 °C.

509. The heater of claim 508, wherein at least a portion of the heater section is exposed to the formation.

510. The heater of claim 508, wherein the stainless steel is at most 10% by weight cobalt.

511. The heater of claim 508, wherein the stainless steel comprises iron and chromium.

512. The heater of claim 508, wherein the stainless steel comprises at most about 22% chromium by weight.

513. The heater of claim 508, wherein the stainless steel is 410 stainless steel.

514. The heater of claim 508, wherein the metal section is substantially inert to galvanic corrosion.

515. The heater of claim 508, wherein the metal section comprises a temperature limited heater section.

516. The heater of claim 508, wherein the exposed metal section is substantially the only electrical path in the heater configured to carry current into and out of a subsurface formation.

517. The heater of claim 508, wherein the heater section is an electrical resistance heater section.

518. A method for heating a subsurface formation using a heater comprising an elongated ferromagnetic metal heater section, wherein the composition of the heater section is such that sulfidation rate of the heater section decreases with increasing temperature of the heater when the heater is at a temperature in a selected temperature range.

519. The method of claim 518, wherein the selected temperature range is in a range of temperatures between about 500 °C and 650 °C.

520. The method of claim 518, wherein the heater section is 410 stainless steel.

521. The method of claim 518, wherein the heater section comprises at least 2.0% cobalt by weight.

522. The method of claim 518, wherein the heater section comprises at most 10% by weight cobalt.

523. The method of claim 518, wherein the heater section is substantially inert to galvanic corrosion.

524. The method of claim 518, wherein the heater section comprises a temperature limited heater section.

525. The method of claim 518, wherein the heater section is substantially the only electrical path in the heater configured to carry current into and out of the formation.

526. The method of claim 518, further comprising applying current to the heater section such that the heater section heats as a result of the electrical resistance of the heater section.

527. The method of claim 518, wherein at least a portion of the heater section is exposed to the formation.

528. The method of claim 518, wherein the subsurface formation comprises hydrocarbons, the method further comprising allowing the heat to transfer to the formation such that at least some hydrocarbons are pyrolyzed in the formation.

529. The method of claim 518, further comprising producing a fluid from the formation.

530. The method of claim 518, further comprising producing a fluid from the formation, and producing a transportation fuel from the produced fluid.

531. A method for heating a subsurface formation using a heater comprising an elongated ferromagnetic metal heater section comprising stainless steel having at least 2.0% cobalt by weight, and wherein the composition of the heater section is such that the sulfidation rate of the heater section is less than about 25 mils per year at a temperature between about 800 °C to about 880 °C.

532. The method of claim 531, wherein the stainless steel is at most 10% by weight cobalt.

533. The method of claim 531, wherein the stainless steel comprises at most about 15% chromium by weight.

534. The method of claim 531, wherein the heater section is substantially inert to galvanic corrosion.

535. The method of claim 531, wherein the heater section is substantially the only electrical path in the heater configured to carry current into and out of a subsurface formation.

536. The method of claim 531, further comprising applying current to the heater section such that the heater section heats as a result of the electrical resistance of the heater section.

537. The method of claim 531, wherein at least a portion of the heater section is exposed to the formation.

538. The method of claim 531, wherein the subsurface formation comprises hydrocarbons, the method further comprising allowing the heat to transfer to the formation such that at least some hydrocarbons are mobilized and/or pyrolyzed in the formation.

539. The method of claim 531, further comprising producing a fluid from the formation.

540. The method of claim 531, further comprising producing a fluid from the formation, and producing a transportation fuel from the produced fluid.

541. A method for treating a hydrocarbon containing formation, comprising:

providing heat from one or more heaters located in a first section of the formation;

allowing some of the heat to transfer from the first section to a second section of the formation, the second section being adjacent to the first section;

producing at least some fluids from the second section of the formation, wherein at least some of the fluids produced in the second section comprise fluids initially in the first section; and

providing heat from one or more heaters located in the second section of the formation after at least some fluids have been produced from the second section.

542. The method of claim 541, wherein at least some of the produced fluids comprise hydrocarbons.

543. The method of claim 541, wherein at least some of the produced fluids comprise hydrocarbons initially in the first section.

544. The method of claim 541, further comprising allowing at least some fluids to flow from the first section to the second section.

545. The method of claim 541, further comprising allowing at least some fluids to flow from the first section to the second section to transfer heat from the first section to the second section.

546. The method of claim 541, wherein the provided heat increases the permeability of the first section and/or the second section.

547. The method of claim 541, wherein the provided heat mobilizes at least some hydrocarbons in the first section and/or the second section.

548. The method of claim 541, wherein the provided heat pyrolyzes at least some hydrocarbons in the first section and/or the second section.

549. The method of claim 541, further comprising dewatering the first section and/or the second section prior to providing heat to the formation.

550. The method of claim 541, wherein the first section and the second section are substantially equal sized sections.

551. The method of claim 541, further comprising injecting a fluid into the first section.

552. The method of claim 541, further comprising:

allowing some of the heat to transfer from the second section to a third section of the formation. the third section being adjacent to the second section and separated from the first section by the second section;

producing at least some fluids from the third section of the formation, wherein at least some of the fluids produced in the third section comprise fluids initially in the first section and/or the second section.

553. The method of claim 552, further comprising providing heat from one or more heaters located in the second section of the formation after at least some fluids have been produced from the second section.

554. The method of claim 552, further comprising shutting down production in the second section after production in the third section is started.

555. A method for treating a hydrocarbon containing formation, comprising:

providing heat from one or more heaters located in two or more first sections of the formation;

allowing some of the heat to transfer from the first sections to two or more second sections of the formation;

wherein the first sections and the second sections are arranged in a checkerboard pattern, the checkerboard pattern having each first section substantially surrounded by one or more of the second sections and each second section substantially surrounded by one or more of the first sections;

producing at least some fluids from the second sections of the formation, wherein at least some of the fluids produced in the second sections comprise fluids initially in the first sections; and

providing heat from one or more heaters located in the second sections of the formation after at least some fluids have been produced from the second sections.

556. The method of claim 555, wherein at least some of the produced fluids comprise hydrocarbons.

557. The method of claim 555, wherein at least some of the produced fluids comprise hydrocarbons initially in the first sections.

558. The method of claim 555, further comprising allowing at least some fluids to flow from the first sections to the second sections.

559. The method of claim 555, further comprising allowing at least some fluids to flow from the first sections to the second sections to transfer heat from the first sections to the second sections.

560. The method of claim 555, wherein the provided heat increases the permeability of at least one of the first sections and/or at least one of the second sections.

561. The method of claim 555, wherein the provided heat mobilizes at least some hydrocarbons in the first sections and/or the second sections.

562. The method of claim 555, wherein the provided heat pyrolyzes at least some hydrocarbons in the first sections and/or the second sections.

563. The method of claim 555, further comprising dewatering at least one of the first sections and/or at least one of the second sections prior to providing heat to the formation.

564. The method of claim 555, wherein the first sections and the second sections are substantially equal sized sections.

565. The method of claim 555, further comprising injecting a fluid into at least one of the first sections.

566. A method for treating a hydrocarbon containing formation, comprising:

treating a first zone of the formation at or near a center of a treatment area;

beginning treatment of a plurality of zones of the formation at selected times after the treatment of the first zone begins, the treatment of each successively treated zone beginning at a selected time after treatment of the previous zone begins;

wherein each successively treated zone is adjacent to the zone treated previously;

wherein the successive treatment of the zones proceeds in an outward spiral sequence from the first zone so that the treatment of the zones moves outwards towards the boundary of the treatment area;

wherein treatment of each of the zones comprises:

providing heat from one or more heaters located in two or more first sections of the zone;

allowing some of the heat to transfer from the first sections to two or more second sections of the zone;

wherein the first sections and the second sections are arranged in a checkerboard pattern within the zone, the checkerboard pattern having each first section substantially surrounded by one or more of the second sections and each second section substantially surrounded by one or more of the first sections;

producing at least some fluids from the second sections, wherein at least some of the fluids produced in the second sections comprise fluids initially in the first sections; and

providing heat from one or more heaters located in the second sections after at least some fluids have been produced from the second sections.

567. The method of claim 566, further comprising providing a barrier around at least a portion of the treatment area.

568. The method of claim 566, further comprising allowing outer zones of the formation to expand inwards into pore spaces in previously treated zones to minimize shearing in the formation.

569. The method of claim 566,wherein the outward spiral sequence minimizes and/or inhibits expansion stresses in the formation.

570. The method of claim 566, further comprising providing one or more support portions in the formation between one or more of the zones.

571. The method of claim 570, wherein the support portions provide support against geomechanical shifting, shearing, and/or expansion stress in the formation.

572. The method of claim 566, wherein at least some of the produced fluids comprise hydrocarbons.

573. The method of claim 566, wherein at least some of the produced fluids comprise hydrocarbons initially in the first sections.

574. The method of claim 566, further comprising allowing at least some fluids to flow from the first sections to the second sections.

575. The method of claim 566, further comprising allowing at least some fluids to flow from the first sections to the second sections to transfer heat from the first sections to the second sections.

576. The method of claim 566, wherein the provided heat increases the permeability of at least one of the first sections and/or at least one of the second sections.

577. The method of claim 566, wherein the provided heat mobilizes at least some hydrocarbons in the first sections and/or the second sections.

578. The method of claim 566, wherein the provided heat pyrolyzes at least some hydrocarbons in the first sections and/or the second sections.

579. The method of claim 566, further comprising dewatering at least one of the first sections and/or at least one of the second sections prior to providing heat to the formation.

580. The method of claim 566, wherein the first sections and the second sections are substantially equal sized sections.

581. The method of claim 566, further comprising injecting a fluid into at least one of the first sections.

582. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;

allowing the heat to transfer from the heaters so that at least a portion of the formation reaches a visbreaking temperature;

maintaining a pressure in the formation below a fracture pressure of the formation; and

producing at least some visbroken fluids from the formation.

583. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;

allowing the heat to transfer from the heaters so that at least a portion of the formation reaches a visbreaking temperature;

maintaining a pressure in the formation below a fracture pressure of the formation while allowing the portion of the formation heats to the visbreaking temperature;

reducing the pressure in the formation to a selected pressure after the portion of the formation reaches the visbreaking temperature; and

producing fluids from the formation.

584. The method of claim 583, wherein the visbreaking temperature is between about 200 °C and about 240 °C.

585. The method of claim 583, further comprising operating the heaters at full power until the portion of the formation reaches the visbreaking temperature.

586. The method of claim 583, further comprising maintaining the pressure in the formation below the fracture pressure of the formation by removing at least some fluids from the formation.

587. The method of claim 583, wherein the fracture pressure of the formation is between about 2000 kPa and about 10000 kPa.

588. The method of claim 583, wherein the selected pressure is at most about 1000 kPa.

589. The method of claim 583, wherein the selected pressure is a pressure at which coke formation is inhibited in the formation.

590. The method of claim 583, further comprising increasing the temperature of the portion of the formation to pyrolysis temperatures after reducing the pressure to the selected pressure.

591. The method of claim 583, further comprising producing at least some mobilized hydrocarbons from the formation.

592. The method of claim 583, further comprising producing at least some visbroken hydrocarbons from the formation.

593. The method of claim 583, further comprising producing at least some pyrolyzed hydrocarbons from the formation.

594. The method of claim 583, further comprising varying the amount of mobilized hydrocarbons, visbroken hydrocarbons, and pyrolyzed hydrocarbons produced from the formation to vary a quality of the fluids produced from the formation.

595. The method of claim 583, further comprising varying the amount of mobilized hydrocarbons, visbroken hydrocarbons, and pyrolyzed hydrocarbons produced from the formation to vary the total recovery of hydrocarbons from the formation.

596. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;

allowing the heat to transfer from the heaters to at least a portion of the formation;

controlling conditions in the formation so that water is recondensed in the formation in situ; and

producing fluids from the formation.

597. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from one or more heaters located in the formation;

creating an injection zone in the formation with the provided heat, the injection zone having a permeability sufficient enough to allow injection of a drive fluid into the zone;

providing the drive fluid into the injection zone; and

producing fluids from the formation.

598. The method of claim 597, wherein the heaters are turned off after creating the injection zone.

599. The method of claim 597, wherein the drive fluid mobilizes at least some hydrocarbons in the formation.

600. The method of claim 597, further comprising providing at least some heat to the formation using the drive fluid.

601. The method of claim 597, wherein the drive fluid comprises pressurized steam.

602. The method of claim 597, wherein the formation has little or no initial injectivity.

603. The method of claim 597, wherein the injection zone comprises a fluid production network between at least one of the heaters and a production well.

604. The method of claim 597, wherein the formation comprises a karsted formation.

605. A method for treating a tar sands formation, comprising:

providing heat to a portion of a hydrocarbon layer in the formation from one or more heaters located in the formation;

providing a drive fluid to a part of the portion of the formation behind a heat front generated by the heaters; and

producing fluids from the part of the formation behind the heat front.

606. A method for treating a tar sands formation, comprising:

providing a drive fluid to a first portion of the formation to mobilize at least some hydrocarbons in the first portion;

allowing at least some of the mobilized hydrocarbons to flow into a second portion of the formation;

providing heat to the second portion the formation from one or more heaters located in the formation; and

producing at least some hydrocarbons from the second portion of the formation.

607. A method for treating a tar sands formation, comprising:

providing heat from one or more heaters to one or more karsted zones of the tar sands formation;

mobilizing hydrocarbon fluids in the formation; and

producing hydrocarbon fluids from the formation.

608. The method of claim 607, wherein one or more karsted zones are selectively heated.

609. The method of claim 607, further comprising flowing the mobilized hydrocarbon fluids in an interconnected pore network of the formation.

610. The method of claim 607, further comprising flowing the mobilized hydrocarbons fluids in an interconnected pore network of the formation, wherein the interconnected pore network comprises a plurality of vugs.

611. The method of claim 607, wherein the heat is provided to mobilize hydrocarbons in vugs of the formation.

612. The method of claim 607, further comprising pyrolyzing at least some hydrocarbons in the formation.

613. The method of claim 607, wherein the formation includes vugs having a porosity of at least 20 porosity units in a formation with a porosity of at most about 15 porosity units, and wherein the vugs include unmobilized hydrocarbons prior to heating.

614. The method of claim 607, further comprising draining mobilizing hydrocarbon fluids to a production well in the formation.

615. The method of claim 607, wherein the formation is a karsted carbonate formation containing viscous hydrocarbons.

616. The method of claim 607, further comprising injecting steam into the formation.

617. The method of claim 607, further comprising heating the formation with the one or more heaters to increase steam injectivity, and then injecting steam in the formation.

618. A method for treating a karsted formation containing heavy hydrocarbons, comprising:

providing heat to at least part of one or more karsted layers in the formation from one or more heaters located in the karsted layers;

allowing the provided heat to reduce the viscosity of at least some hydrocarbons in the karsted layers; and

producing at least some hydrocarbons from at least one of the karsted layers of the formation.

619. A method for treating a karsted formation containing heavy hydrocarbons, comprising:

providing heat to at least part of one or more karsted layers in the formation from one or more heaters located in the karsted layers;

allowing the provided heat to reduce the viscosity of at least some hydrocarbons in the karsted layers to get an injectivity in at least one of the karsted layers sufficient to allow a drive fluid to flow in the karsted layers;

providing the drive fluid into at least one of the karsted layers; and

producing at least some hydrocarbons from at least one of the karsted layers of the formation.

620. A method for treating a formation containing dolomite and hydrocarbons, comprising:

providing heat at less than the decomposition temperature of dolomite from one or more heaters to at least a portion of the formation;

mobilizing hydrocarbon fluids in the formation; and

producing hydrocarbon fluids from the formation.

621. The method of claim 620, further comprising providing heat at or higher than the decomposition temperature of dolomite to produce carbon dioxide.

622. The method of claim 620, further comprising providing heat at or higher than the decomposition temperature of dolomite to produce carbon dioxide, the heating being conducted such that carbon dioxide provides a gas cap on the formation.

623. The method of claim 620, further comprising providing heat at or higher than the decomposition temperature of dolomite to produce carbon dioxide, the heating being provided such that the carbon dioxide mixes with hydrocarbons in the formation and reduces the viscosity of such hydrocarbons.

624. The method of claim 620, wherein the heat is less than about 407 °C.

625. The method of claim 620, further comprising flowing the mobilized hydrocarbon fluids in an interconnected pore network of the formation.

626. The method of claim 620, further comprising flowing the mobilized hydrocarbons fluids in an interconnected pore network of the formation, wherein the interconnected pore network comprises a plurality of vugs.

627. The method of claim 620, wherein the heat is provided to mobilize hydrocarbons in vugs of the formation.

628. The method of claim 620, further comprising pyrolyzing at least some hydrocarbons in the formation.

629. The method of claim 620, wherein the formation includes vugs having a porosity of at least 20 porosity units in a formation with a porosity of at most about 15 porosity units, and wherein the vugs include unmobilized hydrocarbons prior to heating.

630. The method of claim 620, further comprising draining mobilizing hydrocarbon fluids to a production well in the formation.

631. The method of claim 620, further comprising injecting steam into the formation.

632. The method of claim 620, further comprising heating the formation with the one or more heaters to increase steam injectivity, and then injecting steam in the formation.

633. A method for treating a karsted formation containing heavy hydrocarbons, comprising:

providing heat to at least part of one or more karsted layers in the formation from one or more heaters located in the karsted layers;

allowing a temperature in at least one of the karsted layers to reach a decomposition temperature of dolomite in the formation;

allowing the dolomite to decompose; and

producing at least some hydrocarbons from at least one of the karsted layers of the formation.

634. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from one or more heaters located in the formation;

allowing the pressure to increase in an upper portion of the formation to provide a gas cap in the upper portion; and

producing at least some hydrocarbons from a lower portion of the formation.

635. A method for treating a karsted formation containing heavy hydrocarbons, comprising:

providing heat to at least part of one or more karsted layers in the formation from one or more heaters located in the karsted layers;

allowing a temperature in at least one of the karsted layers to reach a decomposition temperature of dolomite in the formation;

allowing the dolomite to decompose and produce carbon dioxide;

maintaining the carbon dioxide in the formation to provide a gas cap in an upper portion of at least one of the karsted layers; and

producing at least some hydrocarbons from at least one of the karsted layers of the formation.

636. A method for treating a tar sands formation, the method comprising the steps of:

providing heat to a portion of a hydrocarbon layer in the formation from one or more heaters located in the formation;

providing a drive fluid to a part of the formation; and

producing fluids from the formation.

637. The method of claim 636, wherein the drive fluid is provided from a well having a well length adapted to emit the drive fluid from the well to the formation, and the provided heat increases injectivity of drive fluid from the well from at most about 10 kg/m/day of steam to at least about 100 kg/m/day of steam, and where injectivity is the mass of steam that can be injected per unit well length that is adapted to emit the drive fluid from the well to the formation, per day.

638. The method of claim 636, wherein the provided heat decreases a viscosity of fluids in the formation to less than about 500 cp for a distance of about 2 m from at least one of the heaters.

639. The method of claim 636, wherein the provided heat decreases a viscosity of fluids in the formation with an initial viscosity of above about 10000 cp.

640. The method of claim 636, wherein the drive fluid is steam.

641. The method of claim 636, wherein the drive fluid is provided to a part of the formation to which heat has been provided.

642. The method of claim 636, wherein the fluid is produced from a portion of the formation to which heat has been provided.

643. The method of claim 642, wherein the portion of the formation to which drive fluid is provided is above the portion of the formation from which fluids are produced.

644. The method of claim 636, wherein the drive fluid is provided to a part of the formation to which heat has been provided and the fluid is produced from a portion of the formation to which heat has been provided, and there is at least one path from the portion of the formation to which the drive fluid is provided to the portion of the formation from which fluids are produced, and wherein the viscosity of fluids in the path has been reduced to below about 500 cp by the provided heat.

645. The method of claim 644, wherein the viscosity of the fluids in the formation in the path from the portion of the formation to which drive fluid is provided and the portion of the formation from which fluids are produced is reduced from an initial viscosity of above about 10000 cp by the provided heat.

646. The method of claim 645, wherein fluids in the at least one path from the portion of the formation to which the drive fluid is provided to the portion of the formation from which fluids are produced have a viscosity which has been reduced to below about 100 cp by the provided heat.

647. The method of claim 646, wherein the drive fluid is steam.

648. The method of claim 647, wherein the portion of the formation to which drive fluid is provided is above the portion of the formation from which fluids are produced.

649. A composition comprising:

from about percent 18 to about 22 percent by weight chromium;

from about percent 12 to about 13 percent by weight nickel;

between about 3 percent by weight and about 10 percent by weight copper;

from about 1 percent to about 10 percent by weight manganese;

from about 0.3 percent to about 1 percent by weight silicon;

from about 0.5 percent to about 1.5 percent by weight niobium; and

from about 38 percent to about 63.5 percent by weight iron.

650. The composition of claim 649, further comprising from about 0.2 percent to 0.5 percent by weight nitrogen.

651. The composition of claim 649, further comprising 0.3 percent to 1 percent by weight molybdenum.

652. The composition of claim 649, further comprising from about 0.08 percent to 0.2 percent by weight carbon.

653. The composition of claim 649, further comprising from about 0.01 percent to 2 percent by weight tungsten.

654. The composition of claim 649, wherein the composition comprises nanonitride precipitates.

655. The composition of claim 654, wherein the nanonitride precipitates comprise particles having maximum dimensions in the range of about five to one hundred nanometers.

656. The composition of claim 654, wherein the composition further comprise nanocarbide precipitates.

657. The composition of claim 656, wherein the nanocarbide precipitates comprise particles having maximum dimensions in the range of about five to two hundred nanometers.

658. The composition of claim 649, wherein the composition, when at 800°C, has at least 3.25 percent by weight of precipitates.

659. The composition of claim 658, wherein at least two percent by weight of the precipitates present at 800°C are Cu, M(C,N), $M_2(C,N)$ or $M_{23}C_6$ phases.

660. The composition of claim 658, wherein the composition has been annealed at an annealing temperature, and the composition comprises at least 1.5 percent by weight more Cu, M(C,N), $M_2(C,N)$ or $M_{23}C_6$ phases at 800°C than at the annealing temperature.

661. The composition of claim 660, wherein the annealing temperature is at least 1250°C.

662. The composition of claim 660, wherein the annealing temperature is at between 1300°C and the melting temperature of the composition.

663. The composition of claim 649, wherein the composition, when at 800°C, has at least 4 percent by weight of precipitates.

664. The composition of claim 649, wherein the composition, when at 800°C, has at least 8 percent by weight of precipitates.

665. A composition comprising:

from about 18 percent to 22 percent by weight chromium;

from about 10 percent to 14 percent by weight nickel;

from about 1 percent to 10 percent by weight copper;

from about 0.5 percent to 1.5 percent by weight niobium;

from about 36 percent to 70.5 percent by weight iron; and

precipitates of nanonitrides.

666. The composition of claim 665, wherein the nanonitride precipitates comprise particles having a maximum dimension of between five and one hundred nanometers.

667. The composition of claim 666, wherein the composition, when at 800 °C, has at least 3.25 percent by weight of precipitates.

668. The composition of claim 666, wherein the composition, when at 800°C, has at least 4 percent by weight of precipitates.

669. The composition of claim 665, wherein at least 2 percent by weight of the precipitates present at 800°C are Cu, M(C,N), $M_2(C,N)$ or $M_{23}C_6$ phases.

670. The composition of claim 665, wherein the composition has been subjected to cold work.

671. The composition of claim 665, wherein the composition has been subjected to hot work.

672. The composition of claim 665, wherein the composition has been subjected to hot aging.

673. A heater system comprising:

a heat generating element; and

a canister surrounding the heat generating element, wherein the canister is at least partially made of a material comprising:

from about 18 percent to about 22 percent by weight chromium;

from about 10 percent to about 14 percent by weight nickel;

from about 1 percent to 10 percent by weight copper;

from about 0.5 percent to 1.5 percent by weight niobium;

from about 36 percent to 70.5 percent by weight iron; and

precipitates of nanonitrides.

674. The heater system of claim 673, wherein the heat generating element is an electrical powered heat generating element.

675. The heater system of claim 673 wherein the heat generating element is a hydrocarbon fuel burning element.

676. A system for heating a subterranean formation comprising a tubular, the tubular at least partially made from a material comprising:

from about 18 percent to 22 percent by weight chromium;

from about 10 percent to 14 percent by weight nickel;

from about 1 percent to 10 percent by weight copper;

from about 0.5 percent to 1.5 percent by weight niobium;

from about 36 percent to 70.5 percent by weight iron; and

precipitates of nanonitrides.

677. The system of claim 676, wherein a heating medium is circulated through the tubular to heat the subterranean formation.

678. The system of claim 676, wherein the heating medium comprises steam.

679. The system of claim 676, wherein the heating medium comprises carbon dioxide.

680. The system of claim 676, wherein the heating medium is heated at the surface by exchanging heat with helium.

681. The system of claim 680, wherein the helium is heated in a nuclear reactor.

682. The system of claim 676, wherein the system further comprises an electrically powered heating element as a source of heat.

683. The system of claim 676, wherein the tubular is fabricated by welding a rolled plate of material to form a tubular.

684. The system of claim 683, wherein the welding comprises laser welding.

685. The system of claim 683, wherein the welding comprises gas tungsten arc-welding.

686. A composition comprising:

about 11 percent to about 14 percent by weight Cr;

about 6 percent to about 12 percent by weight Co;

about 0.01 percent to about 0.15 percent by weight C;

about 0.1 percent to about 1.0 percent by weight Si; and

about 65 percent to about 82 percent by weight Fe.

687. The composition of claim 686, further comprising about 0.01 percent to about 1 percent by weight Mn.

688. The composition of claim 686, further comprising 0.1 percent to about 0.75 percent by weight Ni.

689. The composition of claim 686, wherein the composition comprises about 8 percent to about 10 percent Co.

690. The composition of claim 686, wherein the composition comprises less than about 0.75 % by weight Ni.

691. The composition of claim 686, wherein the composition comprises more than about 76 percent by weight Fe.

692. A heater comprising a metal section comprising:

iron, cobalt, and carbon;

wherein the heater section has a Curie temperature (T_c) less than a phase transformation temperature, wherein the T_c is at least 800 °C; and

wherein the heater section is configured to provide, when time varying current is applied, an electrical resistance.

693. The heater of claim 692, wherein the metal section further comprises one or more metals capable of forming carbides.

694. The heater of claim 692, wherein the metal section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is vanadium.

695. The heater of claim 692, wherein metal section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is titanium.

696. The heater of claim 692,wherein the metal section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is vanadium and/or titanium.

697. The heater of claim 692, wherein the metal section further comprises manganese.

698. The heater of claim 692, wherein the metal section further comprises nickel.

699. The heater of claim 692, wherein the metal section further comprises silicon.

700. The heater of claim 692, wherein the metal section further comprises chromium.

701. The heater of claim 692, wherein the metal section further comprises manganese, silicon, chromium, or combinations thereof.

702. The heater of claim 692, wherein the content of iron in the metal section is at least 50% by weight.

703. The heater of claim 692, wherein the content of cobalt in the metal section is at least 2% by weight.

704. The heater of claim 692, wherein the metal section has at most 1% by weight of manganese.

705. The heater of claim 692, wherein the metal section has at most 1% by weight of nickel.

706. The heater of claim 692, wherein the metal section has at most 1% by weight of silicon.

707. The heater of claim 692, wherein the metal section has at most 1% by weight of vanadium.

708. The heater of claim 692, wherein the metal section has at most 1% by weight of titanium.

709. The heater of claim 692, wherein the metal section has at most 1% by weight of manganese.

710. A method of heating a formation containing hydrocarbons, comprising:

providing a temperature limited heater to a formation, wherein the heater comprises a metal section comprising iron, cobalt, and carbon, wherein the heater section has a Curie temperature (T_c) less than a phase transformation temperature, wherein the T_c is at least 800 °C; and

providing current to the temperature limited heater such that the temperature limited heater provides electrical resistance heating to at least a portion of the formation.

711. A heater comprising a metal section comprising:

iron, cobalt, chromium and carbon;

wherein the heater section has a Curie temperature (T_c) less than a phase transformation temperature, wherein the T_c is at least 740 °C; and

wherein the heater section is configured to provide, when time varying current is applied, an electrical resistance.

712. The heater of claim 711, wherein the metal section further comprises one or more metals capable of forming carbides.

713. The heater of claim 711, wherein the metal section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is vanadium.

714. The heater of claim 711, wherein metal section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is titanium.

715. The heater of claim 711, wherein the metal section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is vanadium and/or titanium.

716. The heater of claim 711, wherein the metal section further comprises manganese.

717. The heater of claim 711, wherein the metal section further comprises nickel.

718. The heater of claim 711, wherein the metal section further comprises silicon.

719. The heater of claim 711, wherein the metal section further comprises manganese, silicon, chromium, or combinations thereof.

720. The heater of claim 711, wherein the content of iron in the metal section is at least 50% by weight.

721. The heater of claim 711, wherein the content of chromium in the metal section is at least 9% by weight.

722. The heater of claim 711, wherein the content of chromium in the metal section is at least 11% by weight.

723. The heater of claim 711, wherein the content of cobalt in the metal section is at least 6% by weight.

724. The heater of claim 711, wherein the metal section has at most 1% by weight of manganese.

725. The heater of claim 711, wherein the metal section has at most 1% by weight of nickel.

726. The heater of claim 711, wherein the metal section has at most 1% by weight of silicon.

727. The heater of claim 711, wherein the metal section has at most 1% by weight of vanadium.

728. The heater of claim 711, wherein the metal section has at most 1% by weight of titanium.

729. The heater of claim 711, wherein the metal section has at most 1% by weight of manganese.

730. A method of heating a formation containing hydrocarbons, comprising:

providing a temperature limited heater to a formation, wherein the heater comprises a metal section comprising iron, cobalt, chromium and carbon, wherein the heater section has a Curie temperature (T_c) less than a phase transformation temperature, wherein the T_c is at least 740 °C; and

providing current to the temperature limited heater such that the temperature limited heater provides electrical resistance heating to at least a portion of the formation.

731. A heater comprising:

a metal section having at least 50% by weight iron, at least 6% by weight cobalt, at least 9% by weight chromium, and at least 0.5% by weight vanadium;

wherein the heater section has a Curie temperature (T_c) less than a phase transformation temperature, wherein the T_c is at least 740 °C; and

wherein the heater section is configured to provide, when time varying current is applied, an electrical resistance.

732. The heater of claim 731, wherein the metal section further comprises carbon.

733. The heater of claim 731, wherein metal section further comprises titanium.

734. The heater of claim 731,wherein the metal section further comprises manganese.

735. The heater of claim 731, wherein the metal section further comprises nickel.

736. The heater of claim 731,wherein the metal section further comprises silicon.

737. The heater of claim 731, wherein the metal section further comprises manganese, silicon, nickel, or combinations thereof.

738. The heater of claim 731,wherein the content of chromium in the metal section is at least 11% by weight.

739. The heater of claim 731, wherein the metal section has at most 1% by weight of manganese.

740. The heater of claim 731, wherein the metal section has at most 1% by weight of nickel.

741. The heater of claim 731, wherein the metal section has at most 1% by weight of silicon.

742. The heater of claim 731, wherein the metal section has at most 1% by weight of vanadium.

743. The heater of claim 731, wherein the metal section has at most 1% by weight of titanium.

744. The heater of claim 731, wherein the metal section has at most 1% by weight of manganese.

745. A method of heating a formation containing hydrocarbons, comprising:

providing a temperature limited heater to a formation, wherein the heater comprises a metal section having at least 50% by weight iron, at least 6% by weight cobalt, at least 9% by

weight chromium, and at least 0.5% by weight vanadium; wherein the heater section has a Curie temperature (T_c) less than a phase transformation temperature, wherein the T_c is at least 740 °C; and

providing current to the temperature limited heater such that the temperature limited heater provides electrical resistance heating to at least a portion of the formation.

746. A heater comprising:

a metal section having at least 50% by weight iron, at least 9% by weight chromium and at least 0.1% by weight carbon;

wherein the heater section has a Curie temperature (T_c) less than a phase transformation temperature, wherein the T_c is at least 800 °C; and

wherein the heater section is configured to provide, when time varying current is applied, an electrical resistance.

747. The heater of claim 746, wherein the metal section further comprises one or more metals capable of forming carbides.

748. The heater of claim 746, wherein the metal section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is vanadium.

749. The heater of claim 746, wherein metal section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is titanium.

750. The heater of claim 746, wherein the metal section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is vanadium and/or titanium.

751. The heater of claim 746, wherein the metal section further comprises manganese.

752. The heater of claim 746, wherein the metal section further comprises nickel.

753. The heater of claim 746, wherein the metal section further comprises silicon.

754. The heater of claim 746, wherein the metal section further comprises manganese, silicon, or combinations thereof.

755. The heater of claim 746, wherein the content of iron in the metal section is at least 50% by weight.

756. The heater of claim 746, wherein the content of chromium in the metal section is at least 11% by weight.

757. The heater of claim 746, wherein the metal section has at least 6% by weight of cobalt.

758. The heater of claim 746, wherein the metal section has at most 1% by weight of manganese.

759. The heater of claim 746, wherein the metal section has at most 1% by weight of nickel.

760. The heater of claim 746, wherein the metal section has at most 1% by weight of silicon.

761. The heater of claim 746, wherein the metal section has at most 1% by weight of vanadium.

762. The heater of claim 746, wherein the metal section has at most 1% by weight of titanium.

763. The heater of claim 746, wherein the metal section has at most 1% by weight of manganese.

764. A method of heating a formation containing hydrocarbons, comprising:

providing a temperature limited heater to a formation, wherein the heater comprises a metal section having at least 50% by weight iron, at least 9% by weight chromium and at least 0.1% by weight carbon. wherein the heater section has a Curie temperature (T_c) less than a phase transformation temperature, wherein the T_c is at least 800 °C; and

providing current to the temperature limited heater such that the temperature limited heater provides electrical resistance heating to at least a portion of the formation.

765. A method of providing at least a partial barrier for a subsurface formation, comprising:

providing an opening in the formation;

providing liquefied wax to the opening, the wax having a solidification temperature that is greater than the temperature of the portion of the formation in which the barrier to desired to be formed;

pressurizing the liquefied wax such that at least a portion of the liquefied wax flows into the formation; and

allowing the wax to solidify to form at least a partial barrier in the formation.

766. The method of claim 765, wherein the wax comprises a surfactant.

767. The method of claim 765,wherein the wax comprises a surfactant selected to increase the miscibility of the wax in the formation.

768. The method of claim 765, wherein the wax viscosity increases quickly as the wax solidifies.

769. The method of claim 765, wherein the wax is selected to resist biological degradation.

770. The method of claim 765, wherein at least 50 weight percent of the wax is a hydrocarbon with branched chains.

771. The method of claim 765, wherein the wax, when flowing in a conduit, solidifies on the inner wall of the conduit, and the solidified wax provides insulation to inhibit further solidification of the wax in the conduit.

772. The method of claim 765, further comprising dewatering at least a portion of the formation.

773. The method of claim 765, further comprising cooling at least a portion of the wax in the formation.

774. The method of claim 765, further comprising providing wax to at least two openings such that the wax from at least two openings mixes and solidifies to form a barrier.

775. The method of claim 765, further comprising heating wax in the opening with a heater.

776. The method of claim 765, further comprising heating wax in the opening with a temperature limited heater.

777. The method of claim 765, further comprising heating wax in the opening with a temperature limited heater such that the wax is not heated above its flash point.

778. The method of claim 765, further comprising providing heat from one or more heaters to a section of the formation to mobilize fluids in the section of the formation, wherein the barrier inhibits flow of fluids into and/or out of the section of the formation.

779. The method of claim 765, further comprising providing heat from one or more heaters to a section of the formation to mobilize fluids in the section of the formation, wherein the barrier inhibits flow of fluids into and/or out of the section of the formation, and producing fluids from the section of the formation.

780. The method of claim 765, further comprising forming a frozen barrier by circulating cooling fluid in the opening.

781. The method of claim 765, further comprising injecting grout into the opening.

782. The method of claim 765, further comprising providing heated water to the opening.

783. The method of claim 765, further comprising providing heated water to the opening, and pressurizing the water.

784. The method of claim 765, further comprising providing water to opening, and heating the water.

785. The method of claim 765, further comprising providing water to the opening, and the pressurizing the water, prior to providing the wax to the opening.

786. The method of claim 765, further comprising inserting a conduit in the opening, and providing pressurized water to a space between the opening and the conduit to at least partially flush wax from the opening.

787. The method of claim 765, further comprising inserting a conduit in the opening, and providing pressurized water to the conduit to at least partially flush wax from the opening.

788. The method of claim 765, wherein the wax is sufficiently pressurized such that wax travels at least about 1 meter into the formation.

789. The method of claim 765, wherein as the wax is provided such that it travels further into the hotter sections of the formation.

790. A method of providing at least a partial barrier for a subsurface formation, comprising:

providing an opening in the formation;

providing a composition including cross-linkable polymer to the opening, the composition being configured to solidify after a selected time in the formation;

pressurizing the composition such that at least a portion of the composition flows into the formation; and

allowing the composition to solidify to form at least a partial barrier in the formation.

791. The method of claim 790, wherein the composition comprises a cross-linking inhibitor.

792. The method of claim 790,wherein the composition comprises a cross-linking initiator and a cross-linking inhibitor.

793. The method of claim 790, wherein the composition comprises a cross-linking inhibitor that is configured to degrade after a selected time in the formation.

794. A method of containing liquid hydrocarbon contaminants in a fracture system of a subsurface formation, comprising:

raising a temperature of the formation near at least one injection well adjacent to a portion of the formation that contains the liquid hydrocarbon contaminants above a melting temperature of a material including wax;

introducing molten material into the formation through the injection well, wherein the molten material enters the fracture system and mixes with the contaminants in the fracture system; and

allowing the molten material to cool in the formation and congeal to form a containment barrier.

795. A method of forming a wellbore in a formation through at least two permeable zones, comprising:

drilling a first portion of the wellbore to a depth between a first permeable zone and a second permeable zone;

heating a portion of the wellbore adjacent to the first permeable zone;

introducing a wax into the wellbore, wherein a portion of the wax enters the first permeable zone and congeals in the first permeable zone to form a barrier; and

drilling a second portion of the wellbore through a second permeable zone to a desired depth.

796. A method for heating a subsurface treatment area, comprising:

producing hot fluid from at least one subsurface layer; and

transferring heat from at least a portion of the hot fluid to the treatment area.

797. The method of claim 796, wherein the hot fluid is produced from a geothermally pressurized geyser.

798. The method of claim 796, wherein the hot fluid is pumped from the subsurface layer.

799. The method of claim 796, wherein transferring heat from the hot fluid to the treatment area comprises circulating hot fluid through wells in the treatment area.

800. The method of claim 796, wherein transferring heat from the hot fluid to the treatment area comprises introducing at least a portion of the hot fluid directly into the treatment area.

801. The method of claim 796, further comprising using the hot fluid to provide heat to the formation for solution mining.

802. The method of claim 796, further introducing the hot fluid as a first fluid in a solution mining process and producing a second fluid from the formation, wherein the second fluid contains at least some minerals dissolved in the first fluid.

803. The method of claim 796, using the hot fluid to preheat at least a section of the treatment area and using heat sources to provide additional heat to the section above a pyrolysis temperature of hydrocarbons in the treatment area.

804. The method of claim 796, further comprising directing the hot fluid to the treatment area without first producing the hot fluid to the surface.

805. A method for heating at least a portion of a subsurface treatment area, comprising:

introducing a fluid into a hot subsurface layer to transfer heat from the hot layer to the fluid;

producing at least a portion of the fluid introduced into the hot layer, wherein the produced fluid is hot fluid at a temperature higher than the temperature of the fluid introduced into the hot layer; and

transferring heat from at least a portion of the hot fluid to the treatment area.

806. The method of claim 805, wherein transferring heat from the hot fluid to the treatment area comprises circulating hot fluid through wells in the treatment area.

807. The method of claim 805, wherein transferring heat from the hot fluid to the treatment area comprises introducing at least a portion of the hot fluid directly into the treatment area.

808. The method of claim 805, further comprising using the hot fluid to provide heat to the formation for solution mining.

809. The method of claim 805, further introducing the hot fluid as a first fluid in a solution mining process and producing a second fluid from the formation, wherein the second fluid contains at least some minerals dissolved in the first fluid.

810. The method of claim 805, using the hot fluid to preheat at least a section of the treatment area and using heat sources to provide additional heat to the section above a pyrolysis temperature of hydrocarbons in the treatment area.

811. The method of claim 805, further comprising directing the hot fluid to the treatment area without first producing the hot fluid to the surface.

812. The method of claim 805, further comprising introducing at least a portion of the hot fluid after the hot fluid has transferred heat to the treatment area back to the hot subsurface layer.

813. A method of treating a subsurface treatment area in a formation, comprising:

heating a treatment area to mobilize formation fluid in the treatment area; and

introducing a fluid into the formation to inhibit migration of formation fluid from the treatment area.

814. The method of claim 813, wherein the fluid comprises carbon dioxide.

815. The method of claim 813, wherein the fluid is introduced into the formation in an area between a barrier and the treatment area.

816. A method for treating a subsurface treatment area in a formation, comprising:

heating a subsurface treatment area with a plurality of heat sources; and

introducing a fluid into the formation from a plurality of wells offset from the heat sources to inhibit outward migration of formation fluid from the treatment area.

817. The method of claim 816, wherein a barrier is offset from the plurality of wells used to introduce the fluid into the formation.

818. The method of claim 816, wherein the fluid comprises carbon dioxide.

819. The method of claim 816, further comprising providing heat to at least a portion the formation adjacent to at least one of the plurality of wells from a heater coupled to the well.

820. The method of claim 816, further comprising providing heat to at least a portion the formation adjacent to at least one of the plurality of wells from a heater coupled to the well, wherein the heater is configured to provide heat without raising the formation above a pyrolysis temperature or a dissociation temperature of minerals in the formation.

821. The method of claim 816, further comprising providing heat to at least a portion of the formation adjacent to at least one of the plurality of wells from a heater well in the formation that is offset from the well.

822. The method of claim 816, further comprising providing heat to at least a portion of the formation adjacent to at least one of the plurality of wells from a heater well in the formation that is offset from the well, wherein the heater is configured to provide heat without raising the formation above a pyrolysis temperature or a dissociation temperature of minerals in the formation.

823. An in situ heat treatment system for producing hydrocarbons from a subsurface formation, comprising:

a plurality of wellbores in the formation;

piping positioned in at least two of the wellbores;

a fluid circulation system coupled to the piping; and

a nuclear reactor configured to heat a heat transfer fluid circulated by the circulation system through the piping to heat the temperature of the formation to temperatures that allow for hydrocarbon production from the formation.

824. The system of claim 823, wherein the heat transfer fluid comprises carbon dioxide.

825. The system of claim 823, wherein the nuclear reactor comprises a pebble bed reactor.

826. A method of heating a subsurface formation, comprising:

heating a heat transfer fluid using heat exchange with helium heated by a nuclear reactor;

circulating the heat transfer fluid through piping in the formation to heat a portion of the formation to allow hydrocarbons to be produced from the formation; and

producing hydrocarbons from the formation.

827. The system of claim 826, wherein the heat transfer fluid comprises carbon dioxide.

828. The system of claim 826, wherein the nuclear reactor comprises a pebble bed reactor.

829. A gas burner assembly for heating a subsurface formation, comprising:

an oxidant line;

a fuel line positioned in the oxidant line; and

a plurality of oxidizers coupled to the fuel line, wherein at least one of the oxidizers includes:

a mix chamber for mixing fuel from the fuel line with an oxidant;

an igniter;

a nozzle and flame holder; and

a heat shield, wherein the heat shield comprises a plurality of openings in communication with the oxidant line.

830. The assembly of claim 829, further comprising a water line positioned in the oxidant line, the water line configured to deliver water that inhibits coking of fuel to the fuel line before a first oxidizer in the gas burner assembly.

831. The assembly of claim 829, wherein the heat shield comprises at least one flame stabilizer.

832. A gas burner assembly for heating a subsurface formation, comprising:

an oxidant line;

a fuel line positioned in the oxidant line; and

a plurality of oxidizers coupled to the fuel line, wherein at least one of the oxidizers includes:

a mix chamber for mixing fuel from the fuel line with an oxidant;

an catalyst chamber configured to produce hot reaction products to ignite fuel and oxidant;

a nozzle and flame holder; and

a heat shield, wherein the heat shield comprises a plurality of openings in communication with the oxidant line.

833. The assembly of claim 832, further comprising a water line positioned in the oxidant line, the water line configured to deliver water that inhibits coking of fuel to the fuel line before a first oxidizer in the gas burner assembly.

834. The assembly of claim 832, wherein the heat shield comprises at least one flame stabilizer.

835. A gas burner assembly for heating a subsurface formation, comprising:

an oxidant line;

a fuel line positioned in the oxidant line; and

a plurality of oxidizers coupled to the fuel line, wherein at least one of the oxidizers includes:

a mix chamber for mixing fuel from the fuel line with an oxidant;

an igniter in the mix chamber configured to ignite fuel and oxidant to preheat fuel and oxidant;

an catalyst chamber configured to react preheated fuel and oxidant from the mix chamber to produce hot reaction products to ignite fuel and oxidant;

a nozzle and flame holder; and

a heat shield, wherein the heat shield comprises a plurality of openings in communication with the oxidant line.

836. The assembly of claim 835, further comprising a water line positioned in the oxidant line, the water line configured to deliver water that inhibits coking of fuel to the fuel line before a first oxidizer in the gas burner assembly.

837. The assembly of claim 835, wherein the heat shield comprises at least one flame stabilizer.

838. A heater, comprising:

a heater section comprising iron, cobalt, and carbon;

wherein the heater section has a Curie temperature (T_c) less than a phase transformation temperature, and the T_c is at least 800 °C; and

wherein the heater section is configured to provide, when time varying current is applied to the heater section, an electrical resistance.

839. The heater of claim 838, wherein the heater section further comprises one or more metals capable of forming carbides.

840. The heater of claim 838, wherein the heater section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is vanadium.

841. The heater of claim 838, wherein heater section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is titanium.

842. The heater of claim 838,wherein the heater section further comprises one or more metals capable of forming carbides, and wherein at least one of the metals is vanadium and/or titanium.

843. The heater of claim 838, wherein the heater section further comprises manganese.

844. The heater of claim 838, wherein the heater section further comprises nickel.

845. The heater of claim 838, wherein the heater section further comprises silicon.

846. The heater of claim 838, wherein the heater section further comprises chromium.

847. The heater of claim 838, wherein the heater section further comprises manganese, silicon, chromium, or combinations thereof.

848. The heater of claim 838, wherein the content of iron in the heater section is at least 50% by weight.

849. The heater of claim 838, wherein the content of cobalt in the heater section is at least 2% by weight.

850. The heater of claim 838, wherein the heater section has at most 1% by weight of manganese.

851. The heater of claim 838, wherein the heater section has at most 1% by weight of nickel.

852. The heater of claim 838, wherein the heater section has at most 1% by weight of silicon.

853. The heater of claim 838, wherein the heater section has at most 1% by weight of vanadium.

854. The heater of claim 838, wherein the heater section has at most 1% by weight of titanium.

855. The heater of claim 838, wherein the heater section has at most 1% by weight of manganese.

856. The heater of claim 838, wherein the heater section is configured to provide a reduced amount of heat at or near, and above, the Curie temperature.

857. The heater of claim 838, wherein the heater is located in a subsurface formation.

858. The heater of claim 838, wherein the heater is configured to provide heat to a subsurface formation.

859. The heater of claim 838, wherein the heater is configured to provide heat to a hydrocarbon containing formation such that at least some hydrocarbons in the formation are mobilized and/or pyrolyzed.

860. A method of heating a hydrocarbon containing formation, comprising:

providing a temperature limited heater to the formation, wherein the heater comprises a heater section comprising iron, cobalt, and carbon, wherein the heater section has a Curie

temperature (T_c) less than a phase transformation temperature, wherein the T_c is at least 800 °C; and

providing current to the temperature limited heater such that the temperature limited heater provides electrical resistance heating to at least a portion of the formation.

861. The method of claim 860, wherein the heater section provides a reduced amount of heat at or near, and above, the Curie temperature.

862. The method of claim 860, further comprising providing heat to the formation such that at least some hydrocarbons in the formation are mobilized and/or pyrolyzed.

863. A heater, comprising:

a heater section comprising iron, cobalt, chromium and carbon;

wherein the heater section has a Curie temperature (T_c) less than a phase transformation temperature, wherein the T_c is at least 740 °C; and

wherein the heater section is configured to provide, when time varying current is applied, an electrical resistance.

864. The heater of claim 863, wherein the heater section further comprises one or more metals capable of forming carbides.

865. The heater of claim 863, wherein the heater section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is vanadium.

866. The heater of claim 863, wherein heater section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is titanium.

867. The heater of claim 863, wherein the heater section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is vanadium and/or titanium.

868. The heater of claim 863, wherein the heater section further comprises manganese.

869. The heater of claim 863, wherein the heater section further comprises nickel.

870. The heater of claim 863, wherein the heater section further comprises silicon.

871. The heater of claim 863, wherein the heater section further comprises manganese, silicon, chromium, or combinations thereof.

872. The heater of claim 863, wherein the content of iron in the heater section is at least 50% by weight.

873. The heater of claim 863, wherein the content of chromium in the heater section is at least 9% by weight.

874. The heater of claim 863, wherein the content of chromium in the heater section is at least 11% by weight.

875. The heater of claim 863, wherein the content of cobalt in the heater section is at least 6% by weight.

876. The heater of claim 863, wherein the heater section has at most 1% by weight of manganese.

877. The heater of claim 863, wherein the heater section has at most 1% by weight of nickel.

878. The heater of claim 863, wherein the heater section has at most 1% by weight of silicon.

879. The heater of claim 863, wherein the heater section has at most 1% by weight of vanadium.

880. The heater of claim 863, wherein the heater section has at most 1% by weight of titanium.

881. The heater of claim 863, wherein the heater section has at most 1% by weight of manganese.

882. The heater of claim 863, wherein the heater section is configured to provide a reduced amount of heat at or near, and above, the Curie temperature.

883. The heater of claim 863, wherein the heater is located in a subsurface formation.

884. The heater of claim 863, wherein the heater is configured to provide heat to a subsurface formation.

885. The heater of claim 863, wherein the heater is configured to provide heat to a hydrocarbon containing formation such that at least some hydrocarbons in the formation are mobilized and/or pyrolyzed.

886. A method of heating a hydrocarbon containing formation, comprising:

providing a temperature limited heater to the formation, wherein the heater comprises a heater section comprising iron, cobalt, chromium and carbon, wherein the heater section has a Curie temperature (T_c) less than a phase transformation temperature, wherein the T_c is at least 740 °C; and

providing current to the temperature limited heater such that the temperature limited heater provides electrical resistance heating to at least a portion of the formation.

887. The method of claim 886, wherein the heater section provides a reduced amount of heat at or near, and above, the Curie temperature.

888. The method of claim 886, further comprising providing heat to the formation such that at least some hydrocarbons in the formation are mobilized and/or pyrolyzed.

889. A heater, comprising:

a heater section having at least 50% by weight iron, at least 6% by weight cobalt, at least 9% by weight chromium, and at least 0.5% by weight vanadium;

wherein the heater section has a Curie temperature (T_c) less than a phase transformation temperature, wherein the T_c is at least 740 °C; and

wherein the heater section is configured to provide, when time varying current is applied, an electrical resistance.

890. The heater of claim 889, wherein the heater section further comprises carbon.

891. The heater of claim 889, wherein the heater section further comprises titanium.

892. The heater of claim 889, wherein the heater section further comprises manganese.

893. The heater of claim 889, wherein the heater section further comprises nickel.

894. The heater of claim 889, wherein the heater section further comprises silicon.

895. The heater of claim 889, wherein the heater section further comprises manganese, silicon, nickel, or combinations thereof.

896. The heater of claim 889,wherein the content of chromium in the heater section is at least 11% by weight.

897. The heater of claim 889, wherein the heater section has at most 1% by weight of manganese.

898. The heater of claim 889, wherein the heater section has at most 1% by weight of nickel.

899. The heater of claim 889, wherein the heater section has at most 1% by weight of silicon.

900. The heater of claim 889, wherein the heater section has at most 1% by weight of vanadium.

901. The heater of claim 889, wherein the heater section has at most 1% by weight of titanium.

902. The heater of claim 889, wherein the heater section has at most 1% by weight of manganese.

903. The heater of claim 889, wherein the heater section is configured to provide a reduced amount of heat at or near, and above, the Curie temperature.

904. The heater of claim 889, wherein the heater is located in a subsurface formation.

905. The heater of claim 889, wherein the heater is configured to provide heat to a subsurface formation.

906. The heater of claim 889, wherein the heater is configured to provide heat to a hydrocarbon containing formation such that at least some hydrocarbons in the formation are mobilized and/or pyrolyzed.

907. A method of heating a hydrocarbon containing formation, comprising:

providing a temperature limited heater to a formation, wherein the heater comprises a heater section having at least 50% by weight iron, at least 6% by weight cobalt, at least 9% by weight chromium, and at least 0.5% by weight vanadium; wherein the heater section has a Curie temperature (T_c) less than a phase transformation temperature, wherein the T_c is at least 740 °C; and

providing current to the temperature limited heater such that the temperature limited heater provides electrical resistance heating to at least a portion of the formation.

908. The method of claim 907, wherein the heater section provides a reduced amount of heat at or near, and above, the Curie temperature.

909. The method of claim 907, further comprising providing heat to the formation such that at least some hydrocarbons in the formation are mobilized and/or pyrolyzed.

910. A heater, comprising:

a heater section having at least 50% by weight iron, at least 9% by weight chromium and at least 0.1% by weight carbon;

wherein the heater section has a Curie temperature (T_c) less than a phase transformation temperature, wherein the T_c is at least 800 °C; and

wherein the heater section is configured to provide, when time varying current is applied, an electrical resistance.

911. The heater of claim 910, wherein the heater section further comprises one or more metals capable of forming carbides.

912. The heater of claim 910, wherein the heater section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is vanadium.

913. The heater of claim 910, wherein the heater section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is titanium.

914. The heater of claim 910, wherein the heater section further comprises one or more metals capable of forming carbides, wherein at least one of the metals is vanadium and/or titanium.

915. The heater of claim 910, wherein the heater section further comprises manganese.

916. The heater of claim 910, wherein the heater section further comprises nickel.

917. The heater of claim 910, wherein the heater section further comprises silicon.

918. The heater of claim 910, wherein the heater section further comprises manganese, silicon, or combinations thereof.

919. The heater of claim 910, wherein the content of iron in the heater section is at least 50% by weight.

920. The heater of claim 910, wherein the content of chromium in the heater section is at least 11% by weight.

921. The heater of claim 910, wherein the heater section has at least 6% by weight of cobalt.

922. The heater of claim 910, wherein the heater section has at most 1% by weight of manganese.

923. The heater of claim 910, wherein the heater section has at most 1% by weight of nickel.

924. The heater of claim 910, wherein the heater section has at most 1% by weight of silicon.

925. The heater of claim 910, wherein the heater section has at most 1% by weight of vanadium.

926. The heater of claim 910, wherein the heater section has at most 1% by weight of titanium.

927. The heater of claim 910, wherein the heater section has at most 1% by weight of manganese.

928. The heater of claim 910, wherein the heater section is configured to provide a reduced amount of heat at or near, and above, the Curie temperature.

929. The heater of claim 910, wherein the heater is located in a subsurface formation.

930. The heater of claim 910, wherein the heater is configured to provide heat to a subsurface formation.

931. The heater of claim 910, wherein the heater is configured to provide heat to a hydrocarbon containing formation such that at least some hydrocarbons in the formation are mobilized and/or pyrolyzed.

932. A method of heating a formation containing hydrocarbons, comprising:

providing a temperature limited heater to a formation, wherein the heater comprises a metal section having at least 50% by weight iron, at least 9% by weight chromium and at least 0.1% by weight carbon. wherein the heater section has a Curie temperature (T_c) less than a phase transformation temperature, wherein the T_c is at least 800 °C; and

providing current to the temperature limited heater such that the temperature limited heater provides electrical resistance heating to at least a portion of the formation.

933. The method of claim 932, wherein the heater section provides a reduced amount of heat at or near, and above, the Curie temperature.

934. The method of claim 932, further comprising providing heat to the formation such that at least some hydrocarbons in the formation are mobilized and/or pyrolyzed.

935. A system for coupling ends of elongated heaters, comprising:

two elongated heaters with an end portion of one heater abutted or near to an end portion of the other heater, the elongated heaters comprising cores and one or more conductors substantially concentrically surrounding the cores, the cores having a lower melting point than the conductors, at least one end portion of at least one conductor having a beveled edge, and at least one end portion of at least one core having a recessed opening;

a core coupling material at least partially inside the recessed opening, the core coupling material extending between the two elongated heaters; and

wherein the gap formed by the beveled edge is configured to be filled with a coupling material for coupling the one or more conductors.

936. The system of claim 935, wherein the end portions of both conductors have beveled edges.

937. The system of claim 935, wherein the end portions of both cores have recessed openings.

938. The system of claim 935, wherein the core comprises copper.

939. The system of claim 935, wherein the core coupling material comprises copper.

940. The system of claim 935, wherein at least one conductor comprises ferromagnetic material.

941. The system of claim 935, wherein the outermost conductor comprises stainless steel.

942. The system of claim 935, wherein the coupling material comprises a non-ferromagnetic material.

943. The system of claim 935, wherein the core coupling material comprises material that thermally expands radially more than the coupling material.

944. The system of claim 935, wherein the elongated heaters comprise cores substantially concentrically surrounded by ferromagnetic conductors, the ferromagnetic conductors substantially concentrically surrounded by an outer electrical conductor.

945. The system of claim 935, wherein the elongated heaters are configured to be coupled by welding together the conductors with the coupling material in the gap formed by the beveled edges.

946. The system of claim 935, wherein electrical current is configured to flow primarily through the core coupling material when an electrical current is applied to the elongated heaters.

947. The system of claim 935, wherein the heaters are configured to be used to heat a subsurface formation.

948. A method for coupling two elongated heaters, comprising:

placing a core coupling material in recesses in the end portions of cores of the two elongated heaters, the cores of the heaters substantially concentrically surrounded by one or more conductors, the cores having a lower melting point than the one or more conductors; and

coupling the end portions of the two heaters by filling gaps between beveled edges of the end portions of the one or more conductors with a coupling material.

949. The method of claim 948, further comprising coupling the end portions of the two heaters by welding together the end portions.

950. The method of claim 948, wherein the coupling material comprises non-ferromagnetic material.

951. The method of claim 948, wherein the core coupling material comprises copper.

952. The method of claim 948, wherein during coupling of the end portions of the two heaters, electricity primarily flows through the core coupling material.

953. The method of claim 948, wherein the two heaters are coupled without welding the cores of the heaters together.

954. The method of claim 948, further comprising installing the heaters in a subsurface formation.

955. The method of claim 948, further comprising applying electrical current to the heaters, and providing heat from the heaters to at least a portion of a subsurface formation.

956. A system for coupling end portions of two elongated heater portions, comprising:

a holding system configured to hold end portions of the two elongated heater portions so that the end portions are abutted together or located near each other;

a shield for enclosing the end portions, the shield configured to inhibit oxidation during welding that joins the end portions together, the shield comprising a hinged door that, when closed, is configured to at least partially isolate the interior of the shield from the atmosphere, and the hinged door, when open, is configured to allow access to the interior of the shield; and

one or more inert gas inlets configured to provide at least one inert gas to flush the system with inert gas during welding of the end portions.

957. The system of claim 956, further comprising at least one source of inert gas.

958. The system of claim 956, wherein the inert gas comprises argon.

959. The system of claim 956, wherein the shield comprises a window configured to allow an operator of the system to view the welding of the end portions.

960. The system of claim 956, wherein the shield, when closed, form a substantially airtight seal to seal off the interior of the shield from the atmosphere.

961. The system of claim 956, wherein the shield is configured to allow a positive pressure of inert gas to be provided during welding of the end portions.

962. The system of claim 956, wherein the shield comprises one or more clamps to secure the end portions of the heaters to the shield.

963. The system of claim 956, wherein the end portions are configured to be orbital welded to join the end portions together.

964. The system of claim 956, wherein the shield is configured to allow the heater portions to be moved through the shield so that a non-welded end portion of one of the heater portions can be positioned for welding to an end portion of a third elongated heater portion.

965. The system of claim 956, further comprising a control circuit configured to monitor hydrocarbon gas concentration in the shield, wherein the control circuit is configured to shut off welding of the end portions when the hydrocarbon gas concentration exceeds a minimum value.

966. The system of claim 956, wherein the heater portions are configured to be used to heat a subsurface formation.

967. A method for coupling end portions of two elongated heater portions, comprising:

holding end portions of two elongated heater portions so that the end portions are abutted together or located near each other;

enclosing the end portions of the heaters in a shield, the shield comprising a hinged door that is configured to at least partially isolate the interior of the shield from the atmosphere when closed, and the hinged door when open is configured to allow access to the interior of the shield when open;

welding the end portions together, the shield inhibiting oxidation during the welding; and

providing an inert gas to flush the system during welding of the end portions of the heaters.

968. The method of claim 967, wherein the shield forms an airtight seal to seal off the interior of the shield from the atmosphere when closed.

969. The method of claim 967, wherein the inert gas comprises argon.

970. The method of claim 967, further comprising providing a positive pressure of inert gas into the shield.

971. The method of claim 967, further comprising pulling a vacuum on the interior of the shield prior to welding the end portions together and before providing the inert gas.

972. The method of claim 967, further comprising viewing the welding of the end portions through a window.

973. The method of claim 967, further comprising orbital welding the end portions together.

974. The method of claim 967, further comprising securing the end portions to the shield by clamping the end portions to the shield.

975. The method of claim 967, further comprising moving the elongated heater portions through the shield so that a non-welded end portion of one of the heater portions is positioned for welding to an end portion of a third elongated heater portion.

976. The method of claim 967, further comprising coupling a plurality of additional elongated heater portions to the two elongated heater portions by repeating the method to weld the end portions of each of the additional elongated heater portions to previously welded heater portions, thereby forming an elongated heater.

977. The method of claim 967, further comprising monitoring hydrocarbon gas concentration in the shield, and shutting off welding of the end portions when the hydrocarbon gas concentration exceeds a minimum value.

978. The method of claim 976, further comprising installing the elongated heater in a subsurface formation.

979. The method of claim 976, further comprising applying electrical current to the elongated heater, and providing heat from the heater to at least a portion of a subsurface formation.

980. A heater, comprising:

a ferromagnetic conductor; and

an electrical conductor electrically coupled to the ferromagnetic conductor;

wherein the heater is configured to provide a first amount of heat at a lower temperature and, the heater is configured to provide a second reduced amount of heat when the heater reaches

a selected temperature, or enters a selected temperature range, at which the ferromagnetic conductor undergoes a phase transformation.

981. The heater of claim 980, wherein the ferromagnetic conductor is positioned relative to the outer electrical conductor such that an electromagnetic field produced by time-varying current flow in the ferromagnetic conductor confines a majority of the flow of the electrical current to the outer electrical conductor at temperatures below or near the selected temperature.

982. The heater of claim 980, wherein the electrical conductor provides a majority of a resistive heat output of the heater at temperatures up to approximately the selected temperature, or the selected temperature range, of the phase transformation of the ferromagnetic conductor.

983. The heater of claim 980, wherein the phase transformation comprises a crystalline phase transformation.

984. The heater of claim 980, wherein the phase transformation comprises a change in the crystal structure of the ferromagnetic material.

985. The heater of claim 980, wherein the phase transformation comprises the transformation of the ferromagnetic conductor from ferrite to austenite.

986. The heater of claim 980, wherein the heater self-limits at a temperature near the phase transformation temperature or temperature range.

987. The heater of claim 980, wherein the phase transformation is reversible.

988. The heater of claim 980, wherein the Curie temperature of the ferromagnetic material is within the temperature range of the phase transformation of the ferromagnetic material.

989. The heater of claim 980, wherein the ferromagnetic conductor comprises additional material configured to adjust the selected temperature, or the selected temperature range, of the ferromagnetic conductor.

990. The heater of claim 989, wherein the additional material is configured to adjust the width of the temperature range of the phase transformation.

991. The heater of claim 980, wherein the heater has a turndown ratio of at least 2 to 1.

992. The heater of claim 980, wherein the heater is configured to provide heat to a hydrocarbon containing layer in a hydrocarbon containing formation such that heat transfers from the heater to hydrocarbons in the hydrocarbon containing layer to at least mobilize some hydrocarbons in the layer.

993. A heater, comprising:

a ferromagnetic conductor;

an electrical conductor electrically coupled to the ferromagnetic conductor;

wherein the electrical conductor provides a majority of a resistive heat output of the heater at temperatures up to approximately the selected temperature, or the selected temperature range, of the phase transformation of the ferromagnetic conductor; and

the heater is configured to provide a first amount of heat at a lower temperature and, the heater is configured to provide a second reduced amount of heat when the heater reaches a selected temperature, or enters a selected temperature range, at which the ferromagnetic conductor undergoes a phase transformation.

994. A method of heating a subsurface formation, comprising:

providing electrical current to a ferromagnetic conductor and an electrical conductor electrically coupled to the ferromagnetic conductor to provide heat to at least a portion of the subsurface formation;

wherein a first amount of heat is provided at a lower temperature and, a second reduced amount of heat is provided when the ferromagnetic conductor reaches a selected temperature, or enters a selected temperature range, at which the ferromagnetic conductor undergoes a phase transformation.

995. The method of claim 994, wherein the ferromagnetic conductor is positioned relative to the outer electrical conductor such that an electromagnetic field produced by time-varying current flow in the ferromagnetic conductor confines a majority of the flow of the electrical current to the outer electrical conductor at temperatures below or near the selected temperature.

996. The method of claim 994, wherein the electrical conductor provides a majority of a resistive heat output at temperatures up to approximately the selected temperature, or the selected temperature range, of the phase transformation of the ferromagnetic conductor.

997. The method of claim 994, wherein the phase transformation comprises a crystalline phase transformation.

998. The method of claim 994, wherein the phase transformation comprises a change in the crystal structure of the ferromagnetic material.

999. The method of claim 994, wherein the phase transformation comprises the transformation of the ferromagnetic conductor from ferrite to austenite.

1000.The method of claim 994, wherein the phase transformation is reversible.

1001.The method of claim 994, wherein the ferromagnetic conductor comprises additional material configured to adjust the selected temperature, or the selected temperature range, of the ferromagnetic conductor.

1002.The method of claim 1001, wherein the material addition is configured to adjust the width of the temperature range of the phase transformation.

1003.The method of claim 994, wherein the heater has a turndown ratio of at least 2 to 1.

1004.The method of claim 994, wherein the subsurface formation comprises hydrocarbons, the method further comprising allowing the heat to transfer to the formation such that at least some hydrocarbons are pyrolyzed in the formation.

1005.The method of claim 994, further comprising producing a fluid from the formation.

1006.The method of claim 994, further comprising producing a composition comprising hydrocarbons from the subsurface formation.

1007.The method of claim 994, further comprising producing a transportation fuel from hydrocarbons produced from the subsurface formation.

1008.A method for treating a hydrocarbon containing formation, comprising:

providing heat for a first amount of time to a first hydrocarbon layer in the formation from a first heater located in an opening in the formation, the opening and the first heater having a substantially horizontal or inclined portion located in the first hydrocarbon layer in the formation and at least one connecting portion extending between the substantially horizontal or inclined portion and the surface;

removing at least one connecting portion of the first heater from the opening;

placing an isolation material in the opening such that the isolation material at least partially isolates the layer in which the substantially horizontal or inclined portion of the first heater is located;

forming an additional substantially horizontal or inclined opening portion in a second hydrocarbon layer, the additional portion extending from at least one of the connecting portions of the opening;

placing a second heater in the additional substantially horizontal opening portion; and

providing heat from the second heater to the second hydrocarbon layer.

1009.The method of claim 1008, further comprising producing fluids from the formation.

1010.The method of claim 1008, wherein the first amount of time is sufficient time to produce a selected amount of hydrocarbons from the first hydrocarbon layer.

1011.The method of claim 1008, wherein at least one of the connecting portions is coupled to an end portion of the substantially horizontal or inclined portion.

1012.The method of claim 1008, wherein the second hydrocarbon layer is separated from the first hydrocarbon layer by an at least partially impermeable layer.

1013.The method of claim 1008, further comprising placing the isolation material in at least one of the connecting portions.

1014.The method of claim 1008, wherein the isolation material at least partially isolates the opening above the first hydrocarbon layer or, alternatively, below the first hydrocarbon layer.

1015.The method of claim 1008, further comprising uncoupling at least one connecting portion of the first heater from the substantially horizontal portion of the first heater;

1016.The method of claim 1008, further comprising abandoning the first hydrocarbon layer after treating the formation by leaving the packing in place in the opening.

1017.The method of claim 1008, wherein the connecting portion of the first heater is uncoupled from the substantially horizontal portion of the first heater by breaking one or more links on the first heater.

1018.The method of claim 1017, wherein the breaking is performed by pulling one or more of the connecting portions with a sufficient amount of force.

1019.The method of claim 1008, wherein the formation comprises an oil shale formation.

1020.The method of claim 1008, wherein the first hydrocarbon layer has a higher richness than the second hydrocarbon layer.

1021.The method of claim 1008, wherein the first hydrocarbon layer is at a greater depth than the second hydrocarbon layer.

1022.The method of claim 1008, wherein the impermeable material provides an impermeable layer between the first hydrocarbon layer and the second hydrocarbon layer.

1023.The method of claim 1008, wherein the opening has a first end portion at a first location on the surface of the formation and a second end portion at a second location on the surface of the formation.

1024.The method of claim 1008, wherein the opening comprises a u-shaped opening.

1025.The method of claim 1008, wherein the connecting portions of the opening comprise relatively vertical portions.

1026.The method of claim 1008, wherein the substantially horizontal portion of the opening extends between at least two relatively vertical connecting portions of the opening in the first hydrocarbon layer.

1027.The method of claim 1008, wherein the additional substantially horizontal portion of the opening extends between at least two relatively vertical connecting portions of the opening in the second hydrocarbon layer.

1028.The method of claim 1008, wherein the substantially horizontal portion of the first heater is left in the substantially horizontal portion of the opening after removing the connecting portions of the first heater from the opening.

1029.The method of claim 1008, further comprising producing a composition comprising hydrocarbons from the first hydrocarbon layer and/or the second hydrocarbon layer.

1030.The method of claim 1008, further comprising producing a transportation fuel made from hydrocarbons produced from the first hydrocarbon layer and/or the second hydrocarbon layer.

1031.A method for treating a hydrocarbon containing formation, comprising:

providing heat for a first amount of time to a first hydrocarbon layer in the formation from a first heater located in an opening in the formation, the opening and the first heater having a substantially horizontal or inclined portion located in the first hydrocarbon layer in the formation and two connecting portions extending between the substantially horizontal or inclined portion and the surface, each connecting portion being coupled to one of the end portions of the substantially horizontal or inclined portion;

removing at least one connecting portion of the first heater from the opening;

placing an isolation material in the opening such that the isolation material at least partially isolates the layer in which the substantially horizontal or inclined portion of the first heater is located;

forming an additional substantially horizontal or inclined opening portion in a second hydrocarbon layer, the additional portion extending between the connecting portions of the opening;

placing a second heater in the additional substantially horizontal opening portion; and

providing heat from the second heater to the second hydrocarbon layer.

1032.A method for treating a hydrocarbon containing formation, comprising:

providing heat for a first amount of time to a first hydrocarbon layer in the formation from a first heater located in an opening in the formation, the opening and the first heater having a substantially horizontal or inclined portion located in the first hydrocarbon layer in the formation and a connecting portion extending between the substantially horizontal or inclined portion and the surface, the connecting portion being coupled to an end portion of the substantially horizontal or inclined portion;

removing at least the connecting portion of the first heater from the opening;

placing an isolation material in the opening such that the isolation material at least partially isolates the layer in which the substantially horizontal or inclined portion of the first heater is located;

forming an additional substantially horizontal or inclined opening portion in a second hydrocarbon layer, the additional portion extending from the connecting portion of the opening;

placing a second heater in the additional substantially horizontal opening portion; and

providing heat from the second heater to the second hydrocarbon layer.

1033.A method for producing hydrocarbons from a subsurface formation, comprising:

providing heat to the subsurface formation using an in situ heat treatment process;

forming one or more formation particles, wherein the formation particles are formed during heating of the subsurface formation; and

producing a fluid comprising hydrocarbons and the formation particles from the subsurface formation, wherein the formation particles in the produced fluid comprise cenospheres and have an average particle size of at least 0.5 micrometers.

1034.The method of claim 1033, wherein a majority of the formation particles have an average diameter ranging between 0.5 microns and 200 microns.

1035.The method of claim 1033, wherein the formation particles have an average diameter between 5 microns and 100 microns.

1036.The method of claim 1033, wherein one or more of the formation particles comprises one or more organic compounds.

1037.The method of claim 1033, wherein one or more of the formation particles comprises a mixture of organic and inorganic compounds.

1038.The method of claim 1033, wherein one or more of the formation particles comprises asphaltenes.

1039.The method of claim 1033, wherein one or more of the formation particles comprises clay.

1040.The method of claim 1033, wherein one or more of the formation particles comprises quartz.

1041.The method of claim 1033, wherein one or more of the formation particles comprises one or more zeolites.

1042.The method of claim 1033, wherein forming one or more formation particles produces a bimodal distribution of formation particles.

1043.The method of claim 1033, wherein forming one or more formation particles produces a trimodal distribution of formation particles.

1044.The method of claim 1033, further comprising removing formation particles from the produced fluid.

1045.The method of claim 1033, further comprising filtering the produced fluid to remove selected formation particles.

1046.The method of claim 1033, further comprising centrifuging the produced fluid to remove selected formation particles.

1047.The method of claim 1033, further comprising treating the produced fluid to agglomerate selected formation particles, and then removing the agglomerated formation particles from the produced fluid.

1048.A formation fluid composition, comprising:

hydrocarbons having a boiling range distribution between -5 °C and 600 °C; and

one or more formation particles, wherein one or more of the formation particles comprises cenospheres and wherein one or more of the formation particles have an average particle size of at least 0.5 micrometers.

1049.The formation fluid composition of claim 1048, wherein a majority of the formation particles have an average diameter ranging between 0.5 microns and 200 microns.

1050.The formation fluid composition of claim 1048, wherein the formation particles have an average diameter between 5 microns and 100 microns.

1051.The formation fluid composition of claim 1048, wherein one or more of the formation particles further comprises one or more organic compounds.

1052.The formation fluid composition of claim 1048, wherein one or more of the formation particles further comprises organic and/or inorganic compounds.

1053.The formation fluid composition of claim 1048, wherein one or more of the formation particles further comprises asphaltenes.

1054.The formation fluid composition of claim 1048, wherein one or more of the formation particles further comprises clay.

1055.The formation fluid composition of claim 1048, wherein one or more of the formation particles further comprises quartz.

1056.The formation fluid composition of claim 1048, wherein one or more of the formation particles further comprises one or more zeolites.

1057.The formation fluid composition of claim 1048, wherein a distribution of the formation particles in the formation fluid is bimodal.

1058.The formation fluid composition of claim 1048, wherein a distribution of the formation particles in the formation fluid is trimodal.

1059.A method of producing transportation fuel, comprising:

providing formation fluid from a subsurface in situ heat treatment process, wherein the formation fluid has a boiling range distribution between -5 °C and 350 °C as determined by ASTM D5307;

separating a liquid stream from the formation fluid;

hydrotreating the separated liquid stream;

distilling the hydrotreated liquid stream to produce a distilled stream, wherein the distilled stream has a boiling range distribution between 150 °C and 350 °C as determined by ASTM D5307; and

combining the distilled liquid stream with one or more additives to produce transportation fuel.

1060.The method of claim 1059, wherein the transportation fuel is suitable for use in aircraft.

1061.The method of claim 1059, wherein the transportation fuel is suitable for use in diesel fuel consuming vehicles and equipment.

1062.The method of claim 1059, wherein the transportation fuel is suitable for use aircraft and in diesel fuel consuming vehicles and equipment.

1063.The method of claim 1059, wherein the transportation fuel is suitable for use military aircraft and in military diesel fuel consuming vehicles and equipment.

1064.The method of claim 1059, wherein separating a liquid stream comprises removing lower boiling hydrocarbons from the formation fluid to obtain the separated liquid stream, wherein the separated liquid stream has a boiling range distribution between 50 °C and 350 °C as determined by ASTM D5307.

1065.The method of claim 1059, wherein the distilled liquid stream has a boiling range distribution between 180 °C and 330 °C as determined by ASTM D5307.

1066.The method of claim 1059, wherein at least 50 percent by weight of hydrocarbons in the separated liquid stream have a carbon number from 4 to 12 as determined by ASTM D6730.

1067.The method of claim 1059, wherein from 60 to 95 percent by weight of hydrocarbons in the separated liquid stream have a carbon number from 8 to 13 as determined by ASTM D6730.

1068.The method of claim 1059, wherein separated liquid stream has at most 15 percent by weight naphthenes, at least 70 percent by weight total paraffins, at most 5 percent by weight olefins, and at most 30% by weight aromatics as determined by ASTM D6730.

1069.The method of claim 1059, wherein the separated liquid stream has a nitrogen content of at least 0.01% by weight as determined by ASTM D5762.

1070.The method of claim 1059, wherein the separated liquid stream has a sulfur content of at least 0.01% by weight as determined by ASTM D4294.

1071.The method of claim 1059, wherein the separated liquid stream has a total aromatic content of at most 30% by weight as determined by ASTM D6730.

1072.The method of claim 1059, wherein the separated liquid stream has a total paraffinic content of at least 70% by weight as determined by ASTM D6730.

1073.The method of claim 1059, wherein the distilled liquid stream has a sulfur content of at most 0.001% by weight as determined by ASTM D4294.

1074.The method of claim 1059, wherein the distilled liquid stream has a total aromatics content of at most 25% by volume as determined by ASTM D1319.

1075.The method of claim 1059, wherein the transportation fuel has a boiling range distribution between 140 °C and 330 °C as determined by ASTM D2887, an API gravity between 37 and 51 as determined by ASTM D1298, a freezing point of at most -47 °C as determined by ASTM D5901; a viscosity of at most 8.0 mm^2/s at -20 °C as determined by ASTM D445, a hydrogen

content of at least 23.4% by weight as determined by ASTM D3343, an aromatics content of at most 25% by volume as determined by ASTM D1319, sulfur content of at most 0.3% by weight as determined by ASTM D4294, a net heat of combustion of at least 42.8 MJ/kg as determined by ASTM D3338; and thermal oxidation stability properties of: a heat tube deposit of at most 3 and a change in pressure drop of at most 25 mm Hg as determined by ASTM D3241.

1076.The method of claim 1059, wherein at least one of the additives comprises corrosion inhibitor, lubricity improver, static dissipate additive, fuel system icing inhibitor, antioxidant, detergents, surfactants, friction modifiers, or mixtures thereof.

1077. A hydrocarbon composition, comprising:

hydrocarbons having a boiling range distribution from about 165 °C to about 260 °C as determined by ASTM Method D5307, wherein the hydrocarbons have been obtained from an in situ heat treatment process;

a sulfur compound content of at most 30 ppm by weight as measured by ASTM Method D4294; and

a wear scar diameter of at most 0.85, as determined by ASTM Method D5001.

1078. The method of claim 1077, wherein the hydrocarbon composition is suitable use as transportation fuel.

1079. The method of claim 1077, wherein the hydrocarbon composition is suitable use as jet fuel.

1080. A hydrocarbon composition produced by a method, comprising:

providing formation fluid from a subsurface in situ heat treatment process, wherein the formation fluid has a boiling range distribution between -5 °C and 350 °C as determined by ASTM Method D5307;

separating a liquid stream from the formation fluid;

hydrotreating the separated liquid stream; and

distilling the hydrotreated liquid stream to produce a hydrocarbon composition stream, wherein the hydrocarbon composition has a boiling range distribution between 165 °C and 260 °C as determined by ASTM Method D5307, a wear scar diameter of at most 0.85 mm as determined by ASTM Method D5001, and a sulfur compound content of at most 30 ppm by weight as determined by ASTM Method 4294.

1081. A method of producing a hydrocarbon composition, comprising:

providing formation fluid from a subsurface in situ heat treatment process, wherein the formation fluid has a boiling range distribution between -5 °C and 350 °C as determined by ASTM Method D5307;

separating a liquid stream from the formation fluid;

hydrotreating the separated liquid stream; and

distilling the hydrotreated liquid stream to produce a distilled stream, wherein the distilled stream has a boiling range distribution between 165 °C and 260 °C as determined by ASTM Method D5307, a wear scar diameter of at most 0.85 mm as determined by ASTM Method D5001, and a sulfur compound content of at most 30 ppm by weight as determined by ASTM Method 4294.

1082. A method for treating a hydrocarbon containing formation, comprising:

providing heat to the formation;

producing heated fluid from the formation; and

generating electricity from at least a portion of the heated fluid using a Kalina cycle.

1083. The method of claim 1082, wherein providing heat to the formation comprises heating the formation using a fireflood.

1084. The method of claim 1082, wherein providing heat to the formation comprises transferring heat to the formation from electrical resistance heaters.

1085. The method of claim 1082, wherein providing heat to the formation comprises transferring heat to the formation from subsurface gas burners.

1086. The method of claim 1082, wherein providing heat to the formation comprises transferring heat to the formation from fluid flowing through conduits positioned in the formation.

1087. The method of claim 1082, wherein the Kalina cycle comprises passing a rich working fluid stream from a separator to a turbine to generate electricity.

1088. The method of claim 1082, wherein the Kalina cycle comprises passing the heated fluid through a first heat exchanger to transfer heat to a first portion of a working fluid; passing a second portion of the working fluid to a second heat exchanger to transfer heat to a lean working fluid stream exiting a separator; and passing the first working fluid stream and the second working fluid stream to the separator.

1089. The method of claim 1082, wherein the Kalina cycle comprises passing the heated fluid through a heat exchanger to transfer heat to a working fluid; and then passing the working fluid to a separator.

1090. The method of claim 1082, wherein the heated fluid comprises fluid produced during an in situ heat treatment process.

1091. The method of claim 1082, wherein the heated fluid comprises fluid produced during a solution mining process.

1092. The method of claim 1082, further comprising using at least a portion of the electricity to power electrical resistance heaters in the formation, or in another formation.

1093. The method of claim 1082, further comprising using a least a portion of the electricity to power a refrigeration system for a barrier around a treatment area.

1094. The method of claim 1082, further comprising using a least a portion of the electricity to power one or more compressors that supply compressed gas to the formation.

1095. The method of claim 1082, wherein a working fluid of the Kalina cycle comprises aqueous ammonia.

1096. The method of claim 1082, wherein a working fluid of the Kalina cycle comprises alkanes.

1097. The method of claim 1082, wherein a working fluid of the Kalina cycle comprises hydrofluorocarbons.

1098. The method of claim 1082, wherein a working fluid of the Kalina cycle comprises alkanes and hydrofluorocarbons.

1099. The method of claim 1082, wherein at least a portion of heat transfer to a working fluid of the Kalina cycle takes place in the heated formation.

1100. A system for generating electricity, comprising:

a plurality of heaters in the formation, the heaters configured to heat a portion of the portion;

a plurality of production wells, the production wells configured to remove heated formation fluid from the heated portion of the formation;

a Kalina cycle system coupled to one or more of the production wells, wherein heat from the heated formation fluid is used by the Kalina cycle system to generate electricity.

1101. The system of claim 1100, wherein at least a portion of a working fluid of the Kalina cycle is directed through a heated portion of the formation to result in the transfer of heat from the heated portion of the formation to the working fluid.

1102. The system of claim 1100, wherein the formation fluid comprises fluid produced during a solution mining process.

1103. The system of claim 1100, wherein the formation fluid comprises fluid produced during an in situ heat treatment process.

1104. A method for forming a barrier around at least a portion of a treatment area in a subsurface formation, comprising:

introducing sulfur into one or more wellbores located inside a perimeter of a treatment area in the formation, wherein the treatment area has a permeability of at least 0.1 darcy; and

allowing at least some of the sulfur to move towards portions of the formation cooler than the melting point of sulfur to solidify the sulfur in the formation to form a barrier.

1105. The method of claim 1104, wherein the treatment area has a permeability of at least 1 darcy.

1106. The method of claim 1104, wherein the treatment area has a permeability of at least 10 darcy.

1107. The method of claim 1104, wherein the treatment area has a permeability of at least 100 darcy.

1108. The method of claim 1104, wherein the permeability of the treatment has been increased by a solution mining process.

1109. The method of claim 1104, wherein the permeability of the treatment has been increased by an in situ heat treatment process.

1110. The method of claim 1104, wherein the sulfur is provided as a liquid into the formation.

1111. The method of claim 1110, wherein the heat of the formation adjacent to the wellbore vaporizes the sulfur.

1112. The method of claim 1104, wherein the sulfur is provided as a vapor into the formation.

1113. The method of claim 1104, wherein the flow of sulfur is directed towards the perimeter of the treatment area.

1114. The method of claim 1104, wherein the wellbores through which sulfur is introduced into the formation are located near the perimeter of the treatment area.

1115. The method of claim 1104, wherein a low temperature barrier at least partially surrounding the treatment area enhances the solidification of the sulfur to form the barrier.

1116. The method of claim 1104, further comprising storing carbon dioxide in the treatment area.

1117. A method of forming a barrier in a formation, comprising:

heating a portion of a formation adjacent to a plurality of wellbores to raise a temperature of the formation adjacent to the wellbores above a melting temperature of sulfur and below a pyrolysis temperature of hydrocarbons in the formation;

introducing molten sulfur into at least some of the wellbores; and

allowing the sulfur to move outwards from the wellbores towards portions of the formation cooler than the melting temperature of sulfur so that the sulfur solidifies in the formation to form a barrier.

1118. The method of claim 1117, wherein at least one heater used to heat the portion of the formation adjacent the wellbores comprises a temperature limited heater.

1119. The method of claim 1117, further comprising solution mining a treatment area inside the barrier.

1120. The method of claim 1117, further comprising using an in situ heat treatment process on a treatment area inside the barrier.

1121. The method of claim 1117, further comprising storing carbon dioxide inside the barrier.

1122. The method of claim 1117, further comprising forming the barrier between a first barrier and a treatment area used to produce formation fluid from the formation.

1123. The method of claim 1117, wherein a temperature of the molten sulfur introduced into the formation is near the melting temperature of sulfur.

1124. A method for providing acidic gas to a subsurface formation, comprising:

providing heat from one or more heaters to a portion of a subsurface formation;

producing fluids from the formation using a heat treatment process, wherein the produced fluids comprise one or more acidic gases; and

introducing at least a portion of one of the acidic gases into the formation, or into another formation, through one or more wellbores at a pressure below a lithostatic pressure of the formation in which the acidic gas is introduced.

1125. The method of claim 1124, wherein at least a portion of the acidic gas comprises hydrogen sulfide and/or carbon dioxide.

1126. The method of claim 1124, wherein at least a portion of the introduced acidic gas comprises hydrogen sulfide and the hydrogen sulfide forms a sulfide layer on the surface of the walls of the wellbores.

1127. The method of claim 1126, wherein at least one of the acidic gases comprises carbon dioxide, and the method further comprising introducing the carbon dioxide into the sulfided wellbore.

1128. The method of claim 1124, wherein at least a portion of the acidic gas reacts in the formation.

1129. The method of claim 1124, wherein at least a portion of the acidic gas is sequestered in the formation.

1130. The method of claim 1124, wherein at least a portion of the acidic gas is introduced near the bottom of the saline aquifer.

1131. The method of claim 1124, wherein at least one of the heaters is a temperature limited heater.

1132. The method of claim 1124, wherein at least one of the heaters is an electrical heater.

1133. A method for providing acidic gas to a subsurface formation, comprising:

providing heat from one or more heaters to a portion of a subsurface formation;

producing fluids from the formation using a heat treatment process, wherein the produced fluids comprise one or more acidic gases;

removing at least a portion of carbon dioxide from the acidic gases;

introducing at least a portion of the carbon dioxide into the formation, or into another formation, through one or more wellbores; and

introducing a fluid in the wellbores used for carbon dioxide introduction to inhibit corrosion in the wellbores.

1134. The method of claim 1133, wherein at least a portion of the carbon dioxide reacts in the formation.

1135. The method of claim 1133, wherein at least a portion of the carbon dioxide is sequestered in the formation.

1136. The method of claim 1133, wherein the fluid comprises one or more corrosion inhibitors.

1137. The method of claim 1133, wherein the fluid comprises one or more polymers.

1138. The method of claim 1133, wherein the fluid comprises one or more surfactants.

1139. The method of claim 1133, wherein the fluid comprises one or more hydrocarbons.

1140. The method of claim 1133, wherein the fluid comprises one or more corrosion inhibitors, one or more surfactants, one or more hydrocarbons, one or more polymers or mixtures thereof.

1141. A composition comprising:

from about 18 percent to about 22 percent by weight chromium;

from about 5 percent to about 13 percent by weight nickel;

between about 3 percent and about 10 percent by weight copper;

from about 1 percent to about 10 percent by weight manganese;

from about 0.3 percent to about 1 percent by weight silicon;

from about 0.5 percent to about 1.5 percent by weight niobium;

from about 0.5 to about 2 percent by weight tungsten; and

from about 38 percent to about 63 percent by weight iron.

1142. The composition of claim 1141, wherein the composition has a yield strength of greater than 35 ksi at about 800°C.

1143. The composition of claim 1141, wherein the composition, after being annealed, has a yield strength at about 800 °C that changes less than 20 percent as a result of being cold worked by twenty percent.

1144. The composition of claim 1141, further comprising from about 0.2 percent to about 0.5 percent by weight nitrogen.

1145. The composition of claim 1141, further comprising about 0.3 percent to about 1 percent by weight molybdenum.

1146. The composition of claim 1141, further comprising from about 0.08 percent to about 0.2 percent by weight carbon.

1147. The composition of claim 1141, wherein the composition comprises nanonitride precipitates.

1148. The composition of claim 1147, wherein the nanonitride precipitates comprise a majority of particles having maximum dimensions in the range of five to one hundred nanometers.

1149. The composition of claim 1147, wherein the composition further comprises nanocarbide precipitates.

1150. The composition of claim 1147, wherein the nanocarbide precipitates comprise particles having maximum dimensions in the range of five to two hundred nanometers.

1151. The composition of claim 1141, wherein the composition, when at about 800 °C, has at least 3.25 percent by weight of precipitates.

1152. The composition of claim 1151, wherein at least two percent by weight of the precipitates present at about 800 °C are Cu, M(C,N), M2(C,N) or M23C6 phases.

1153. The composition of claim 1151, wherein the composition has been annealed at an annealing temperature, and the composition comprises at least 1.5 percent by weight more Cu, M(C,N), M2(C,N) or M23C6 phases at 800°C than at the annealing temperature.

1154. The composition of claim 1153, wherein the annealing temperature is at least 1250 °C.

1155. The composition of claim 1153, wherein the annealing temperature is at between about 1300 °C and the melting temperature of the composition.

1156. The composition of claim 1141, wherein the composition, when at about 800 °C, has at least 4 percent by weight of precipitates.

1157. The composition of claim 1141, wherein the composition, when at about 800 °C, has at least 8 percent by weight of precipitates.

1158. A composition comprising:

from about 18 percent to about 22 percent by weight chromium;

from about 5 percent to about 9 percent by weight nickel;

from about 1 percent to about 6 percent by weight copper;

from about 0.5 percent to about 1.5 percent by weight niobium;

from about 1 to about 10 percent by weight manganese;

from about 0.5 to about 1.5 percent by weight of tungsten;

from about 36 percent to about 74 percent by weight iron; and

precipitates of nanonitrides, wherein the ratio of tungsten to copper is between about 1/10 and 10/1.

1159. The composition of claim 1158, wherein the ratio of copper to manganese is between about 1/5 and 5/1.

1160. The composition of claim 1158, wherein the nanonitride precipitates comprise a majority of particles having a maximum dimension of between five and one hundred nanometers.

1161. The composition of claim 1160, wherein the composition, when at about 800 °C, has at least 3.25 percent by weight of precipitates.

1162. The composition of claim 1160, wherein the composition, when at about 800 °C, has at least 4 percent by weight of precipitates.

1163. The composition of claim 1158, wherein at least 2 percent by weight of the precipitates present at 800°C are Cu, M(C,N), M2(C,N) or M23C6 phases.

1164. The composition of claim 1158, wherein the composition has been subjected to cold work to an extent of at least about 10 percent.

1165. The composition of claim 1158, wherein the composition has been subjected to hot work to an extent of at least about ten percent.

1166. The composition of claim 1158, wherein the composition has been subjected to hot aging.

1167. A heater system comprising:

a heat generating element; and

a canister surrounding the heat generating element, wherein the canister is at least partially made of a material comprising:

from about 18 percent to about 22 percent by weight chromium;

from about 5 percent to about 14 percent by weight nickel;

from about 1 percent to about 10 percent by weight copper;

from about 0.5 percent to about 1.5 percent by weight niobium;

from about 36 percent to about 70.5 percent by weight iron; and

precipitates of nanonitrides.

1168. The heater system of claim 1167, wherein the heat generating element is an electrical powered heat generating element.

1169. The heater system of claim 1167, wherein the heat generating element is a hydrocarbon fuel burning element.

1170. A method of heating a subterranean formation comprising:

positioning one or more heater systems in a subterranean formation, wherein at least one of the heater systems comprises:

a heat generating element; and

a canister surrounding the heat generating element, wherein the canister is at least partially made of a material comprising:

from about 18 percent to about 22 percent by weight chromium;

from about 5 percent to about 14 percent by weight nickel;

from about 1 percent to about 10 percent by weight copper;

from about 0.5 percent to about 1.5 percent by weight niobium; and

from about 36 percent to about 70.5 percent by weight iron; and

allowing heat from the heater system to heat at least a portion of the subterranean formation.

1171. A system for heating a subterranean formation comprising a tubular, the tubular at least partially made from a material comprising:

from about 18 percent to about 22 percent by weight chromium;

from about 10 percent to about 14 percent by weight nickel;

from about 1 percent to about 10 percent by weight copper;

from about 0.5 percent to about 1.5 percent by weight niobium;

from about 36 percent to about 70.5 percent by weight iron; and

precipitates of nanonitrides.

1172. The system of claim 1171, wherein a heating medium is circulated through the tubular to heat the subterranean formation.

1173. The system of claim 1172, wherein the heating medium comprises steam.

1174. The system of claim 1172, wherein the heating medium comprises carbon dioxide.

1175. The system of claim 1172, wherein the heating medium is heated at the surface by exchanging heat with helium.

1176. The system of claim 1175, wherein the helium is heated in a nuclear reactor.

1177. The system of claim 1171, wherein the system further comprises an electrically powered heating element as a source of heat.

1178. The system of claim 1171, wherein the tubular is fabricated by welding a rolled plate of material to form a tubular.

1179. The system of claim 1178, wherein the welding comprises laser welding.

1180. The system of claim 1178, wherein the welding comprises gas tungsten arc-welding.

1181. A method of heating a subterranean formation, comprising:

positioning one or more heater systems in a subterranean formation, wherein at least one of the heater systems comprises a tubular and at least a portion of the tubular is made from a material comprising :

from about 18 percent to about 22 percent by weight chromium;

from about 5 percent to about 14 percent by weight nickel;

from about 1 percent to about 10 percent by weight copper;

from about 0.5 percent to about 1.5 percent by weight niobium; and

from about 36 percent to about 70.5 percent by weight iron; and

allowing heat from the heater system to heat at least a portion of the subterranean formation.

1182. A composition, comprising:

from 18 percent to 22 percent by weight chromium;

from 11 percent to 14 percent by weight nickel;

at most 3 percent by weight copper;

from 1 percent to 10 percent by weight manganese;

at most 0.75 percent by weight silicon;

from 0.5 percent to 1.5 percent by weight niobium;

from 0.5 to 1.5 percent by weight tungsten; and

wherein the material is capable of being cold-worked to form a wrought material.

1183. The composition of claim 1182, wherein the material is capable of being hot-worked.

1184. The composition of claim 1182, further comprising from 0.07 percent to 0.15 percent by weight carbon.

1185. The composition of claim 1182, further comprising from 0.2 percent to 0.5 percent by weight nitrogen.

1186. The composition of claim 1182, further comprising iron.

1187. A system for electrically insulating an overburden portion of a heater wellbore, comprising:

the heater wellbore located in a subsurface formation; and

an electrically insulating casing located in the overburden portion of the heater wellbore, the casing comprising at least one non-ferromagnetic material such that ferromagnetic effects are inhibited in the casing.

1188. The system of claim 1187, wherein the non-ferromagnetic material comprises non-metallic material.

1189. The system of claim 1187, wherein the non-ferromagnetic material comprises fiberglass.

1190. The system of claim 1187, wherein the non-ferromagnetic material comprises high-density polyethylene (HDPE).

1191. The system of claim 1187, wherein the casing consists of non-ferromagnetic material.

1192. The system of claim 1187, wherein the casing comprises a ferromagnetic metal coupled to the inside diameter of a non-ferromagnetic metal such that ferromagnetic effects are inhibited in the casing.

1193. The system of claim 1192, wherein the ferromagnetic metal comprises carbon steel and the non-ferromagnetic metal comprises copper.

1194. The system of claim 1187, further comprising a heater located in the heater wellbore, wherein the heater is configured to provide heat to at least a portion of the subsurface formation.

1195. A method for electrically insulating an overburden portion of a heater wellbore, comprising:

locating an electrically casing in the overburden portion of the heater wellbore in a subsurface formation, wherein the casing comprises at least one non-ferromagnetic material that inhibits ferromagnetic effects in the overburden portion of the heater wellbore.

1196. The method of claim 1195, wherein the non-ferromagnetic material comprises non-metallic material.

1197. The method of claim 1195, wherein the non-ferromagnetic material comprises fiberglass.

1198. The method of claim 1195, wherein the non-ferromagnetic material comprises high-density polyethylene (HDPE).

1199. The method of claim 1195, wherein the casing consists of non-ferromagnetic material.

1200. The method of claim 1195, wherein the casing comprises a ferromagnetic metal coupled to the inside diameter of a non-ferromagnetic metal such that ferromagnetic effects are inhibited in the casing.

1201. The method of claim 1200, wherein the ferromagnetic metal comprises carbon steel and the non-ferromagnetic metal comprises copper.

1202. The method of claim 1195, further comprising installing a heater in the heater wellbore.

1203. The method of claim 1195, further comprising providing heat to at least a portion of the subsurface formation with a heater located in the heater wellbore.

1204. The method of claim 1195, wherein the subsurface formation comprises a hydrocarbon containing formation, the method further comprising providing heat to at least a portion of the formation with a heater located in the heater wellbore such that at least some hydrocarbons are pyrolyzed and/or mobilized in the formation.

1205. The method of claim 1195, wherein the subsurface formation comprises a hydrocarbon containing formation, the method further comprising providing heat to at least a portion of the formation with a heater located in the heater wellbore such that at least some hydrocarbons are pyrolyzed and/or mobilized in the formation, and producing a fluid from the formation.

1206. The method of claim 1195, wherein the subsurface formation comprises a hydrocarbon containing formation, the method further comprising providing heat to at least a portion of the formation with a heater located in the heater wellbore such that at least some hydrocarbons are pyrolyzed and/or mobilized in the formation, and producing a composition comprising hydrocarbons from the formation.

1207. The method of claim 1195, wherein the subsurface formation comprises a hydrocarbon containing formation, the method further comprising providing heat to at least a portion of the formation with a heater located in the heater wellbore such that at least some hydrocarbons are pyrolyzed and/or mobilized in the formation, producing hydrocarbons from the formation, and producing a transportation fuel from hydrocarbons produced from the formation.

1208. A wellhead for coupling to a heater located in a wellbore in a subsurface formation, comprising:

the heater located in the wellbore in the subsurface formation; and

a wellhead coupled to the heater, the wellhead being configured to electrically couple the heater to one or more surface electrical components, and wherein the wellhead comprises at least one non-ferromagnetic material such that ferromagnetic effects are inhibited in the wellhead.

1209. The system of claim 1208, wherein the non-ferromagnetic material comprises non-metallic material.

1210. The system of claim 1208, wherein the non-ferromagnetic material comprises fiberglass.

1211. The system of claim 1208, wherein the non-ferromagnetic material comprises high-density polyethylene (HDPE).

1212. The system of claim 1208, wherein the wellhead consists of non-ferromagnetic material.

1213. The system of claim 1208, wherein the wellhead comprises a ferromagnetic metal coupled to a non-ferromagnetic metal such that ferromagnetic effects are inhibited in the wellhead.

1214. The system of claim 1213, wherein the ferromagnetic metal comprises carbon steel and the non-ferromagnetic metal comprises copper.

1215. The system of claim 1208, further comprising a heater located in the heater wellbore, wherein the heater is configured to provide heat to at least a portion of the subsurface formation.

1216. A method for coupling to a heater in a subsurface wellbore, comprising:

coupling a wellhead to the heater in the wellbore, wherein the wellhead comprises at least one non-ferromagnetic material so that ferromagnetic effects are inhibited in the wellhead.

1217. The method of claim 1217, wherein the non-ferromagnetic material comprises non-metallic material.

1218. The method of claim 1217, wherein the non-ferromagnetic material comprises fiberglass.

1219. The method of claim 1217, wherein the non-ferromagnetic material comprises high-density polyethylene (HDPE).

1220. The method of claim 1217, wherein the wellhead consists of non-ferromagnetic material.

1221. The method of claim 1217, wherein the wellhead comprises a ferromagnetic metal coupled to the inside diameter of a non-ferromagnetic metal such that ferromagnetic effects are inhibited in the casing.

1222. The method of claim 1221, wherein the ferromagnetic metal comprises carbon steel and the non-ferromagnetic metal comprises copper.

1223. The method of claim 1217, further comprising installing the heater in the heater wellbore and coupling the heater to the wellhead.

1224. The method of claim 1217, further comprising electrically coupling one or more surface electrical components to the heater through the wellhead.

1225. The method of claim 1217, further comprising providing heat to at least a portion of the subsurface formation with the heater.

1226. The method of claim 1217, wherein the subsurface formation comprises a hydrocarbon containing formation, the method further comprising providing heat to at least a portion of the formation with the heater such that at least some hydrocarbons are pyrolyzed and/or mobilized in the formation.

1227. The method of claim 1217, wherein the subsurface formation comprises a hydrocarbon containing formation, the method further comprising providing heat to at least a portion of the formation with the heater such that at least some hydrocarbons are pyrolyzed and/or mobilized in the formation, and producing a fluid from the formation.

1228. The method of claim 1217, wherein the subsurface formation comprises a hydrocarbon containing formation, the method further comprising providing heat to at least a portion of the formation with the heater such that at least some hydrocarbons are pyrolyzed and/or mobilized in the formation, and producing a composition comprising hydrocarbons from the formation.

1229. The method of claim 1217, wherein the subsurface formation comprises a hydrocarbon containing formation, the method further comprising providing heat to at least a portion of the formation with the heater such that at least some hydrocarbons are pyrolyzed and/or mobilized in the formation, producing hydrocarbons from the formation, and producing a transportation fuel from hydrocarbons produced from the formation.

1230. A system for providing power to one or more subsurface heaters, comprising:

an intermittent power source;

a transformer coupled to the intermittent power source, the transformer being configured to transform power from the intermittent power source to power with appropriate operating parameters for the heaters; and

a tap controller coupled to the transformer, the tap controller being configured to monitor and control the transformer so that a constant voltage is provided to the heaters from the

transformer regardless of the load of the heaters and the power output provided by the intermittent power source.

1231. The system of claim 1230, further comprising a control system coupled to the tap controller, the control system being configured to operate the tap controller.

1232. The system of claim 1230, further comprising a control system coupled to the tap controller, the control system being configured to operate the tap controller using at least one predictive algorithm.

1233. The system of claim 1230, further comprising one or more sensors coupled to the system, the sensors being configured to monitor one or more operating parameters of the heaters, the intermittent power source, and/or the transformer.

1234. The system of claim 1230, further comprising:

a control system coupled to the tap controller; and

one or more sensors coupled to the system configured to monitor one or more operating parameters of the heaters, the intermittent power source, and/or the transformer;

wherein the control system is configured to operate the tap controller based on operating parameter data collected from the sensors.

1235. The system of claim 1230, wherein the tap controller is configured to store, for future use, load provided by the transformer that is in excess of the load required by the heaters.

1236. The system of claim 1230, wherein the intermittent power source comprises a windmill.

1237. The system of claim 1230, wherein the intermittent power source comprises a gas turbine.

1238. The system of claim 1230, wherein the tap controller is configured to control power output in a range between about 5 megavolt amps (MVA) and about 500 MVA.

1239. The system of claim 1230, wherein the tap controller is configured to automatically control the power provided to the heaters.

1240. The system of claim 1230, wherein the tap controller is configured to automatically control the power provided to the heaters to within about 20% of the power required by the heaters.

1241. A method for controlling power provided to one or more subsurface heaters from an intermittent power source, comprising:

monitoring one or more operating parameters of the heaters, the intermittent power source, and a transformer coupled to the intermittent power source that transforms power from the intermittent power source to power with appropriate operating parameters for the heaters;

controlling the power output of the transformer so that a constant voltage is provided to the heaters regardless of the load of the heaters and the power output provided by the intermittent power source.

1242. The method of claim 1241, further comprising controlling the power output of the transformer using a tap controller coupled to the transformer and the heaters.

1243. The method of claim 1241, further comprising controlling the power output of the transformer using at least one predictive algorithm.

1244. The method of claim 1241, further comprising controlling the power output of the transformer using at least one predictive algorithm that assesses the monitored operating parameters of the heaters, the intermittent power source, and the transformer.

1245. The method of claim 1241, further comprising monitoring the operating parameters of the heaters, the intermittent power source, and the transformer using one or more sensors coupled to the heaters, the intermittent power source, and the transformer.

1246. The method of claim 1241, further comprising storing, for future use, load provided by the transformer that is in excess of the load required by the heaters.

1247. The method of claim 1241, wherein the intermittent power source comprises a windmill.

1248. The method of claim 1241, wherein the intermittent power source comprises a gas turbine.

1249. The method of claim 1241, further comprising controlling the power output of the transformer in a range between about 5 megavolt amps (MVA) and about 500 MVA.

1250. The method of claim 1241, further comprising automatically controlling the power provided to the heaters.

1251. The method of claim 1241, further comprising automatically controlling the power provided to the heaters to within about 20% of the power required by the heaters.

1252. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;

allowing the heat to transfer from the heaters to at least a portion of the formation;

maintaining a pressure in the formation below a fracture pressure of the formation overburden while allowing the portion of the formation to heat to a selected average temperature of at least about 280 °C and at most about 300 °C; and

reducing the pressure in the formation to a selected pressure after the portion of the formation reaches the selected average temperature.

1253. The method of claim 1252, wherein the fracture pressure is about 15000 kPa.

1254. The method of claim 1252, wherein the selected pressure is a pressure below which substantial hydrocarbon coking in the formation occurs when the average temperature in the formation is less than 300 °C.

1255. The method of claim 1252, wherein the selected pressure is between about 100 kPa and about 1000 kPa.

1256. The method of claim 1252, wherein the selected pressure is between about 200 kPa and about 800 kPa.

1257. The method of claim 1252, further comprising producing fluids from the formation.

1258. The method of claim 1252, further comprising producing fluids from the formation to maintain the pressure below the fracture pressure.

1259. The method of claim 1252, wherein the selected average temperature is between about 285 °C and about 295 °C.

1260. The method of claim 1252, further comprising providing a drive fluid to the formation.

1261. The method of claim 1252, further comprising providing steam to the formation.

1262. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;

allowing the heat to transfer from the heaters to at least a portion of the formation;

maintaining a pressure in the formation below a fracture pressure of the formation overburden while allowing the portion of the formation to heat to a selected average temperature range;

producing at least some fluids from the formation to maintain the pressure below the fracture pressure; and

assessing the average temperature in the portion by analyzing at least some of the produced fluids.

1263. The method of claim 1262, further reducing the pressure in the formation to a selected pressure after the portion of the formation reaches the selected average temperature range.

1264. The method of claim 1262, wherein the selected average temperature range comprises a temperature range from about 280 °C to about 300 °C.

1265. The method of claim 1262, wherein the selected average temperature range is below the temperature at which substantial coking of hydrocarbons occurs in the formation.

1266. The method of claim 1262, further comprising providing steam to the formation.

1267. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;

allowing the heat to transfer from the heaters to at least a portion of the formation;

maintaining a pressure in the formation below a fracture pressure of the formation overburden by producing at least some fluid from the formation;

assessing the hydrocarbon isomer shift of at least a portion of the fluid produced from the formation; and

reducing the pressure in the formation to a selected pressure when the assessed hydrocarbon isomer shift reaches a selected value.

1268. The method of claim 1267, wherein the average temperature in the portion is based on, at least in part, the hydrocarbon isomer shift.

1269. The method of claim 1267, wherein the hydrocarbon isomer shift comprises n-butane-$\delta^{13}C_4$ percentage versus propane-$\delta^{13}C_3$ percentage.

1270. The method of claim 1267, wherein the hydrocarbon isomer shift comprises n-pentane-$\delta^{13}C_5$ percentage versus propane-$\delta^{13}C_3$ percentage.

1271. The method of claim 1267, wherein the hydrocarbon isomer shift comprises n-pentane-$\delta^{13}C_5$ percentage (y-axis) versus n-butane-$\delta^{13}C_4$ percentage.

1272. The method of claim 1267, wherein the hydrocarbon isomer shift comprises i-pentane-$\delta^{13}C_5$ percentage (y-axis) versus i-butane-$\delta^{13}C_4$ percentage.

1273. The method of claim 1267, wherein the selected value of the hydrocarbon isomer shift corresponds to an average temperature between about 280 °C and about 300 °C.

1274. The method of claim 1267, further comprising heating the formation after reducing the pressure.

1275. The method of claim 1267, further comprising producing fluids from the formation after reducing the pressure.

1276. The method of claim 1267, wherein the selected pressure is a pressure below which substantial hydrocarbon coking in the formation occurs when the average temperature in the formation is less than 300 °C.

1277. The method of claim 1267, further comprising providing steam to the formation.

1278. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;

allowing the heat to transfer from the heaters to at least a portion of the formation;

maintaining a pressure in the formation below a fracture pressure of the formation overburden by producing at least some fluid from the formation;

assessing the weight percentage of saturates in at least a portion of the fluid produced from the formation; and

reducing the pressure in the formation to a selected pressure when the assessed weight percentage of saturates reaches a selected value.

1279. The method of claim 1278, wherein the average temperature in the portion is assessed base on, at least in part, the weight percentage of saturates.

1280. The method of claim 1278, wherein the selected value of the weight percentage of saturates corresponds to an average temperature between about 280 °C and about 300 °C.

1281. The method of claim 1278, wherein the selected value of the weight percentage of saturates is about 30%.

1282. The method of claim 1278, further comprising heating the formation after reducing the pressure.

1283. The method of claim 1278, further comprising producing fluids from the formation after reducing the pressure.

1284. The method of claim 1278, wherein the selected pressure is a pressure below which substantial hydrocarbon coking in the formation occurs when the average temperature in the formation is less than 300 °C.

1285. The method of claim 1278, further comprising providing steam to the formation.

1286. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;

allowing the heat to transfer from the heaters to at least a portion of the formation;

maintaining a pressure in the formation below a fracture pressure of the formation overburden by producing at least some fluid from the formation;

assessing the weight percentage of n-C_7 in at least a portion of the fluid produced from the formation; and

reducing the pressure in the formation to a selected pressure when the assessed n-C_7 reaches a selected value.

1287. The method of claim 1286, wherein the average temperature in the portion is assessed based on, at least in part, the weight percentage of n-C_7.

1288. The method of claim 1286, wherein the selected value of the weight percentage of n-C_7 corresponds to an average temperature between 280 °C and 300 °C.

1289. The method of claim 1286, wherein the selected value of the weight percentage of n-C_7 is about 60%.

1290. The method of claim 1286, further comprising heating the formation after reducing the pressure.

1291. The method of claim 1286, further comprising producing fluids from the formation after reducing the pressure.

1292. The method of claim 1286, wherein the selected pressure is a pressure below which substantial hydrocarbon coking in the formation occurs when the average temperature in the formation is less than 300 °C.

1293. The method of claim 1286, further comprising providing steam to the formation.

1294. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;

allowing the heat to transfer from the heaters to at least a portion of the formation;

assessing a viscosity of one or more zones of the hydrocarbon layer;

varying a number of production wells in the zones based on the assessed viscosities, wherein the number of production wells in a first zone of the formation is less than the number of production wells in a second zone of the formation if the viscosity in the first zone is greater than the viscosity in the second zone; and

producing fluids from the formation through the production wells.

1295. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;

allowing the heat to transfer from the heaters to at least a portion of the formation;

assessing a viscosity of one or more zones of the hydrocarbon layer;

varying the heating rates in the zones based on the assessed viscosities, wherein the heating rate in a first zone of the formation is less than the heating rate in a second zone of the formation if the viscosity in the first zone is greater than the viscosity in the second zone; and

producing fluids from the formation.

1296. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;

assessing a viscosity of one or more zones of the hydrocarbon layer;

varying the heater spacing in the zones based on the assessed viscosities, wherein the heater spacing in a first zone of the formation is denser than the heater spacing in a second zone of the formation if the viscosity in the first zone is greater than the viscosity in the second zone;

allowing the heat to transfer from the heaters to the zones in the formation; and

producing fluids from one or more openings located in at least one selected zone to maintain a pressure in the selected zone below a selected pressure.

1297. The method of claim 1296, wherein the selected zone is the first zone of the formation.

1298. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;

allowing the heat to transfer from the heaters to at least a portion of the formation; and

producing fluids from the formation through at least one production well that is located in at least two zones in the formation, the first zone having an initial permeability of at least 1 darcy, the second zone having an initial of at most 0.1 darcy and the two zones are separated by a substantially impermeable barrier.

1299. The method of claim 1298, wherein the substantially impermeable barrier has an initial permeability of at most 10 μdarcy.

1300. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;

allowing the heat to transfer from the heaters to at least a portion of the formation;

wherein heat is transferred to at least two zones in the formation, at least two of the zones being separated by a substantially impermeable barrier, and one or more holes have been formed to connect the zones through the substantially impermeable barrier; and

producing fluids from the formation.

1301. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from a plurality of heaters located in the formation;

allowing the heat to transfer from the heaters to at least a portion of the formation;

maintaining a pressure in the formation below a fracture pressure of the formation while allowing the portion of the formation to heat to a selected average temperature of at least about 280 °C and at most about 300 °C;

reducing the pressure in the formation to a selected pressure after the portion of the formation reaches the selected average temperature;

producing fluids from the formation;

turning off two or more of the heaters after a selected time; and

continuing producing fluids from the formation after the heaters are turned off.

1302. A method for treating a tar sands formation, comprising:

providing heat to at least part of a hydrocarbon layer in the formation from one or more heaters located in the formation;

allowing the heat to transfer from the heaters to at least a portion of the formation such that a drive fluid is produced in situ in the formation;

allowing the drive fluid to move at least some mobilized hydrocarbons from a first portion of the formation to a second portion of the formation; and

producing at least some of the mobilized fluids from the formation.

1303. The method of claim 1302, wherein the drive fluid is steam.

1304. A method for treating a tar sands formation, comprising:

providing a drive fluid to a first hydrocarbon containing layer of the formation to mobilize at least some hydrocarbons in the first layer;

allowing at least some of the mobilized hydrocarbons to flow into a second hydrocarbon containing layer of the formation;

providing heat to the second layer from one or more heaters located in the second layer; and

producing at least some hydrocarbons from the second layer of the formation.

1305. The method of claim 1304, further comprising providing the drive fluid to a third hydrocarbon containing layer of the formation to mobilize at least some hydrocarbons in the third layer.

1306. The method of claim 1304, further comprising providing the drive fluid to a third hydrocarbon containing layer of the formation to mobilize at least some hydrocarbons in the third layer, and allowing at least some of the mobilized hydrocarbons from the third layer to flow into the second layer.

1307. The method of claim 1304, wherein the first layer is above the second layer.

1308. The method of claim 1304, wherein the first layer is below the second layer.

1309. The method of claim 1304, further comprising producing hydrocarbons from the first layer.

1310. The method of claim 1304, further comprising using the produced hydrocarbons in a steam and electricity generation facility, wherein the facility provides steam as the drive fluid to the first layer of the formation, and electricity for at least some of the heaters in the second layer.

1311. A method for treating a tar sands formation, comprising:

providing a drive fluid to a hydrocarbon containing layer of the formation to mobilize at least some hydrocarbons in the first layer;

producing at least some hydrocarbons from the layer;

providing heat to the layer from one or more heaters located in the formation; and

producing at least some upgraded hydrocarbons from the layer of the formation, the upgraded hydrocarbons comprising at least some hydrocarbons that are upgraded compared to hydrocarbons produced by using the drive fluid.

1312. The method of claim 1311, wherein the drive fluid is steam.

1313. A method for treating a tar sands formation, comprising:

providing heat to a hydrocarbon containing layer from one or more heaters located in the formation, wherein the hydrocarbon containing layer has been previously treated using a steam injection and production process; and

producing at least some hydrocarbons from the layer of the formation, the produced hydrocarbons comprising at least some hydrocarbons that are upgraded compared to hydrocarbons produced by the steam injection and production process.

1314. A heating system for a subsurface formation, comprising:

a canister located in an opening in the subsurface formation;

a heater located in the canister, wherein the heater comprises:

an electrical conductor;

an insulation layer at least partially surrounding the electrical conductor;

an electrically conductive sheath at least partially surrounding the insulation layer; and

a metal located in the canister outside of the heater, the metal being configured to melt at a temperature above about 100 °C so that the metal is a molten metal in the canister at operating temperatures of the heater.

1315. The system of claim 1314, wherein the metal, when molten, is configured to thermally transfer heat between the heater and the canister.

1316. The system of claim 1314, wherein the metal, when molten, is configured to thermally conduct heat between the heater and the canister.

1317. The system of claim 1314, wherein the metal, when molten, is configured to thermally convect heat between the heater and the canister.

1318. The system of claim 1314, wherein the heater is configured to be buoyant in the molten metal.

1319. The system of claim 1314, wherein the metal comprises, before being molten, metal particles, pellets, or spheres in the canister.

1320. The system of claim 1314, wherein the metal comprises tin.

1321. The system of claim 1314, wherein the electrical conductor comprises ferromagnetic material that operates as a temperature limited heater.

1322. The system of claim 1314, wherein the metal, when molten, is configured to conduct electricity between the canister and the electrically conductive sheath.

1323. A heating system for a subsurface formation, comprising:

a first heater configuration, comprising:

a conduit located in a first opening in the subsurface formation;

three electrical conductors located in the conduit;

a return conductor located inside the conduit, the return conductor being electrically coupled to the ends of the electrical conductors distal from the surface of the formation; and

insulation located inside the conduit, the insulation being configured to electrically isolate the three electrical conductors, the return conductor, and the conduit.

1324. The system of claim 1323, wherein each of the electrical conductors is coupled to one phase of a single, three-phase wye transformer.

1325. The system of claim 1323, wherein the return conductor is coupled to the neutral of a single, three-phase wye transformer.

1326. The system of claim 1323, wherein each of the electrical conductors is coupled to one phase of a single, three-phase wye transformer, and the return conductor is coupled to the neutral of a single, three-phase wye transformer.

1327. The system of claim 1326, further comprising at least 4 additional heater configurations coupled to the single, three-phase wye transformer.

1328. The system of claim 1326, further comprising at least 10 additional heater configurations coupled to the single, three-phase wye transformer.

1329. The system of claim 1326, further comprising at least 25 additional heater configurations coupled to the single, three-phase wye transformer.

1330. The system of claim 1323, further comprising a second heater configuration, comprising:

a conduit located in a second opening in the subsurface formation;

three electrical conductors located in the conduit;

a return conductor located inside the conduit, the return conductor being electrically coupled to the ends of the electrical conductors distal from the surface of the formation; and

insulation located inside the conduit, the insulation being configured to electrically isolate the three electrical conductors, the return conductor, and the conduit;

wherein the first heater configuration and the second heater configuration are electrically coupled to a single, three-phase wye transformer.

1331. The system of claim 1330, further comprising a third heater configuration, comprising:

a conduit located in a third opening in the subsurface formation;

three electrical conductors located in the conduit;

a return conductor located inside the conduit, the return conductor being electrically coupled to the ends of the electrical conductors distal from the surface of the formation; and

insulation located inside the conduit, the insulation being configured to electrically isolate the three electrical conductors, the return conductor, and the conduit;

wherein the first heater configuration, the second heater configuration, and the third heater configuration are electrically coupled to the single, three-phase wye transformer.

1332. The system of claim 1323, wherein the electrical conductors comprise resistive heating portions located in a hydrocarbon layer in the formation, the hydrocarbon layer being configured to be heated.

1333. The system of claim 1323, wherein the electrical conductors comprise resistive heating portions located in a hydrocarbon layer in the formation, and a more electrically conductive portion located in an overburden section of the formation.

1334. The system of claim 1323, further comprising at least one additional substantially identical heating system located in an additional opening in the subsurface formation, wherein all the heating systems are electrically coupled to a single, three-phase transformer with each of the electrical conductors in each heating system being coupled to one phase of a single, three-phase wye transformer, and the return conductors of each heating system being coupled to the neutral of the single, three-phase wye transformer.

1335. The system of claim 1323, wherein the electrical conductors are at least partially surrounded by an insulation layer and an electrically conductive sheath, the sheath at least partially surrounding the insulation layer.

1336. The system of claim 1323, wherein the insulation comprises two or more layers of insulation in the conduit.

1337. The system of claim 1323, wherein the electrical conductors are the cores of insulated conductor heaters.

1338. The system of claim 1323, further comprising an outer tubular in the first opening, the first heater configuration being located in the outer tubular.

1339. A heating system for a subsurface formation, comprising:

a three-phase wye transformer;

at least five heaters, each heater comprising:

a conduit located in a first opening in the subsurface formation;

three electrical conductors located in the conduit, each electrical conductor being electrically coupled to one phase of the transformer;

a return conductor located inside the conduit, the return conductor being electrically coupled to the ends of the electrical conductors distal from the surface of the

formation, and the return conductor being electrically coupled to the neutral of the transformer; and

insulation located inside the conduit, the insulation being configured to electrically isolate the three electrical conductors, the return conductor, and the conduit.

1340. A method for making a heater for a subsurface formation, comprising:

coupling three heaters and a return conductor together, each of the three heaters comprising:

an electrical conductor;

an insulation layer at least partially surrounding the electrical conductor;

coupling additional insulation to the outside of the three heaters and the return conductor;

forming a conduit around the additional insulation, the three heaters, and the return conductor; and

compacting the conduit so that against the additional insulation.

1341. The method of claim 1340, wherein the conduit is formed by rolling a metal plate into a tubular shape around the additional insulation layer, the three heaters, and the return conductor, and welding the lengthwise ends of the plate to form a tubular.

1342. The method of claim 1340, wherein the additional insulation comprises one or more preformed blocks of insulation.

1343. A heating system for a subsurface formation, comprising:

a plurality of substantially horizontally oriented or inclined heater sections located in a hydrocarbon layer in the formation, wherein at least two of the heater sections are substantially parallel to each other in at least a majority of the hydrocarbon layer; and

wherein the ends of at least two of the heater sections in the hydrocarbon layer are electrically coupled to a substantially horizontal, or inclined, electrical conductor oriented substantially perpendicular to the ends of the at least two heater sections.

1344. The system of claim 1343, wherein the single conductor is a neutral or a return for heater sections.

1345. The system of claim 1343, wherein the at least two heater sections are electrically coupled in parallel.

1346. The system of claim 1343, wherein the at least two heater sections are electrically coupled in series.

1347. The system of claim 1343, wherein the ends of the at least two heater sections are coupled to the single conductor using a mousetrap coupling.

1348. The system of claim 1343, wherein the ends of the at least two heater sections are coupled to the single conductor using molten metal.

1349. The system of claim 1343, wherein the single conductor is a tubular into which the ends of the at least two heater sections insert.

1350. A method, comprising:

forming a first wellbore in the formation, wherein a portion of the wellbore is oriented substantially horizontally or at an incline;

positioning an electrical conductor in the first wellbore;

forming at least two additional wellbores in the formation, wherein ends of the additional wellbores intersect with the first wellbore, and wherein at least a majority of a section of the first additional wellbore that passes through a hydrocarbon layer to be heat treated by an in situ heat treatment process is substantially parallel to at least a majority of a section of the second additional wellbore that passes through the hydrocarbon layer;

placing a heater section in at least one of the additional wellbores; and

coupling the heater section to the conductor in the first wellbore.

1351. A method for treating a nahcolite containing subsurface formation, comprising:

removing water from a saline zone in or near the formation;

heating the removed water using a steam and electricity cogeneration facility;

providing the heated water to the nahcolite containing formation;

producing a fluid from the nahcolite containing formation, the fluid comprising at least some dissolved nahcolite; and

providing at least some of the fluid to the saline zone.

1352. The method of claim 1351, wherein the saline zone is up dip from the nahcolite containing formation.

1353. The method of claim 1351, further comprising treating the nahcolite containing formation using an in situ heat treatment process after removing at least some of the nahcolite from the formation.

1354. The method of claim 1351, further comprising using at least some of the heat of the produced fluid to heat the removed water in the steam and electricity cogeneration facility.

1355. The method of claim 1351, further comprising storing the fluid in the saline zone.

1356. An in situ heat treatment system for producing hydrocarbons from a subsurface formation, comprising:

one or more wellbores in the formation;

one or more oxidizers positioned in at least one of the wellbores;

a nuclear reactor configured to provide electricity; and

wherein at least a portion of the electricity provided by the nuclear reactor is used to pressurize fluids provided to at least one of the oxidizers.

1357. The system of claim 1356, wherein the fluid is oxidizing fluid.

1358. The system of claim 1356, wherein the fluid is oxidizer fuel.

1359. A method of heating a portion of a subsurface formation, comprising:

generating electricity using a nuclear reactor;

using at least a portion of the electricity to compress an oxidant stream;

providing the oxidant stream and a fuel stream to one or more wellbores; and

reacting the oxidant and the fuel stream in oxidizers in one or more of the wellbores to generate heat, wherein at least a portion of the generated heat transfers to the formation.

1360. The method of claim 1359, wherein the oxidant stream comprises air.

1361. The method of claim 1359, further comprising using at least a portion of the electricity to compress the fuel.

1362. A method of heating a portion of a subsurface formation, comprising:

placing in a wellbore a plurality of encapsulated nuclear material elements in a sufficient quantity to result in the generation of heat from the encapsulated nuclear material elements; and

heating a portion of the formation adjacent to the wellbore by transfer of heat from the encapsulated nuclear material elements.

1363. The method of claim 1362, wherein the wellbore comprises a u-shaped wellbore.

1364. The method of claim 1362, further comprising removing elements from the wellbore and replacing the removed elements with additional elements.

1365. The method of claim 1362, further comprising passing a heat transfer fluid through the wellbore.

1366. The method of claim 1362, further comprising passing a heat transfer fluid through the wellbore, wherein the heat transfer fluid comprises helium.

1367. The method of claim 1362, further comprising passing a heat transfer fluid through the wellbore, and generating electricity with heat transferred to the heat transfer fluid.

1368. The method of claim 1362, wherein the heating mobilizes at least some hydrocarbons in the portion of the formation.

1369. The method of claim 1362, further comprising producing a fluid comprising hydrocarbons mobilized by the heating.

1370. A system for heating a portion of a subsurface formation, comprising:

a wellbore in the formation;

a plurality of encapsulated nuclear material elements located in the wellbore in a sufficient amount to result in the generation of heat from the elements.

1371. The system of claim 1370, wherein the wellbore comprises a u-shaped wellbore.

1372. The system of claim 1370, further comprising a heat transfer fluid circulation system coupled to the wellbore to pass a heat transfer fluid through the wellbore.

1373. The system of claim 1370, further comprising a heat transfer fluid circulation system coupled to the wellbore, wherein a heat transfer fluid used in the heat transfer fluid circulation system comprises helium.

1374. The system of claim 1370, further comprising a heat recovery system coupled to the wellbore wherein the heat recovery system is configured to convert heat from a heat transfer fluid that flows through the wellbore to electricity.

1375. A nuclear heater assembly for heating a subsurface formation, comprising:

at least one fuel conduit, wherein at least one of the fuel conduits is configured to contain two or more nuclear pebble materials.

1376. A nuclear heater assembly for heating a subsurface formation, comprising:

an outer conduit, wherein at least a portion of the outer conduit is positioned in a subsurface formation, wherein the outer conduit is configured to supply a heat transfer fluid; and

at least one fuel conduit, wherein at least a portion of at least one of the fuel conduits is positioned in the outer conduit, and wherein at least one of the fuel conduits is configured to contain two or more nuclear pebble materials.

1377. The assembly of claim 1376, wherein the outer conduit comprises a corrosion resistant material.

1378. The assembly of claim 1376, wherein the outer conduit comprises stainless steel.

1379. The assembly of claim 1376, wherein the fuel conduit is configured to reflect neutrons.

1380. The assembly of claim 1376, wherein the fuel conduit comprises substantially pure iron.

1381. The assembly of claim 1376, wherein the heat transfer fluid comprises a nonreactive gas.

1382. The assembly of claim 1376, wherein the heat transfer fluid comprises helium.

1383. The assembly of claim 1376, wherein one or more of the nuclear pebble materials comprises uranium-235 enriched up to about 9%.

1384. The assembly of claim 1376, wherein one or more of the nuclear pebble materials comprises at least partially depleted uranium-235.

1385. The assembly of claim 1376, wherein at least one of the fuel conduits comprises an inner diameter less than twice a diameter of the nuclear pebble material.

1386. The assembly of claim 1376, wherein one or more of the nuclear pebble materials comprises an outer diameter from about 5 to about 7 centimeters.

1387. The assembly of claim 1376, further comprising one or more neutron reflectors.

1388. The assembly of claim 1376, further comprising one or more neutron reflectors positioned proximate one or more of the nuclear pebble materials.

1389. The assembly of claim 1376, further comprising one or more neutron reflectors positioned proximate one or more of the nuclear pebble materials, wherein one or more of the neutron reflectors are rollable.

1390. The assembly of claim 1376, further comprising one or more neutron reflectors comprising substantially pure iron.

1391. A method of heating a subsurface formation, comprising:

providing one or more nuclear pebble materials to a nuclear heater assembly positioned in a subsurface formation comprising positioning a fuel conduit in an outer conduit of the nuclear heater assembly; and

providing a heat transfer fluid to the nuclear heater assembly between the outer surface of the fuel conduit and the inner surface of the outer conduit.

1392. A method of heating a portion of a subsurface formation, comprising:

introducing an oxidant into a wellbore through a first conduit;

introducing coal and a carrier gas into the wellbore in a second conduit;

passing a portion of the oxidant through one or more critical flow orifices to mix the oxidant with the coal at selected locations; and

reacting the mixture of the coal and the oxidant to generate heat, wherein a portion of the generated heat transfers to the formation.

1393. The method of claim 1392, wherein the first conduit is positioned in the second conduit.

1394. The method of claim 1392, wherein the second conduit is positioned in the first conduit.

1395. The method of claim 1392, wherein the carrier gas comprises carbon dioxide.

1396. The method of claim 1392, wherein the carrier gas comprises nitrogen.

1397. The method of claim 1392, further comprising removing combustion gases from the formation through a third conduit, and wherein flow of combustion gases through the third conduit is countercurrent to flow of oxidant in the first conduit.

1398. The method of claim 1392, further comprising shielding at least one reaction zone where coal and oxidant react to stabilize the reaction zone.

1399. A method of heating a portion of a subsurface formation, comprising:

introducing an oxidant into a wellbore through a first conduit;

introducing coal and a carrier gas into the wellbore in a second conduit;

passing a portion of the coal and the carrier gas through one or more critical flow orifices to mix the coal and the carrier gas with oxidant at selected locations; and

reacting the mixture of the coal and the oxidant to generate heat, wherein a portion of the generated heat transfers to the formation.

1400. The method of claim 1399, wherein the first conduit is positioned in the second conduit.

1401. The method of claim 1399, wherein the second conduit is positioned in the first conduit.

1402. The method of claim 1399, wherein the carrier gas comprises carbon dioxide.

1403. The method of claim 1399, wherein the carrier gas comprises nitrogen.

1404. The method of claim 1399, further comprising removing combustion gases from the formation through a third conduit, and wherein flow of combustion gases through the third conduit is countercurrent to flow of oxidant in the first conduit.

1405. The method of claim 1399, further comprising shielding at least one reaction zone where coal and oxidant react to stabilize the reaction zone.

1406. A heater assembly for heating a subsurface formation, comprising:

an oxidant conduit, wherein the oxidant conduit is configured to supply an oxidizing fluid; and

a fuel conduit, wherein the fuel conduit is configured to supply a fuel fluid comprising pulverized coal.

1407. A heater assembly for heating a subsurface formation, comprising:

an oxidant conduit, wherein the oxidant conduit is configured to supply an oxidizing fluid; and

a fuel conduit, wherein the fuel conduit is configured to supply a fuel fluid comprising coal suspended in a carrier gas.

1408. The assembly of claim 1407, wherein the oxidant conduit comprises an inner conduit positioned in the fuel conduit.

1409. The assembly of claim 1407, wherein the fuel conduit comprises an inner conduit positioned in the oxidant conduit.

1410. The assembly of claim 1407, wherein the fuel conduit comprises an inner conduit positioned in the oxidant conduit, and wherein the fuel fluid is delivered at a higher pressure than the oxidant fluid.

1411. The assembly of claim 1407, wherein the fuel conduit comprises an inner conduit positioned in the oxidant conduit, and wherein the oxidant fluid is delivered at a higher pressure than the fuel fluid.

1412. The assembly of claim 1407, wherein the coal comprises pulverized coal.

1413. The assembly of claim 1407, wherein the carrier gas comprises a non-oxidizing gas.

1414. The assembly of claim 1407, wherein the carrier gas comprises a non-oxidizing gas comprising carbon dioxide gas and/or nitrogen gas.

1415. The assembly of claim 1407, wherein the fuel conduit comprises two or more heat shields coupled to the fuel conduit.

1416. The assembly of claim 1407, wherein the fuel conduit comprises two or more critical flow orifices.

1417. The assembly of claim 1407, wherein the oxidizing fluid comprises oxygen.

1418. The assembly of claim 1407, wherein the oxidizing fluid comprises air.

1419. The assembly of claim 1407, wherein the oxidizing fluid comprises oxygen-enriched air.

1420. The assembly of claim 1407, wherein the oxidant conduit comprises two or more critical flow orifices.

1421. A method of heating a subsurface formation, comprising:

supplying an oxidizing fluid using an oxidant conduit to a subsurface formation; and

supplying a fuel fluid using a fuel conduit to a subsurface formation, wherein the fuel fluid comprises coal suspended in a carrier fluid.

1422. A method of suspending heaters in a well, comprising:

providing a first heater in a first opening and a second heater in a second opening, wherein the first and second openings are in a wellhead positioned over a well;

activating a movement control mechanism coupled to the well head;

inhibiting movement of the first and second heaters in a direction into the well using the activated movement control mechanism; and

inhibiting movement of the first and second heaters in a direction out of the well using the activated movement control mechanism.

1423. The method of claim 1422, wherein the movement control mechanism comprises a two-way slip mechanism.

1424. A system configured to suspend heaters in a well, comprising:

a wellhead positioned over a well;

a movement control mechanism positionable in the wellhead, wherein the movement control mechanism comprises a first opening and a second opening;

a first heater positionable in the first opening; and

a second heater positionable in the second opening;

wherein the movement control mechanism is configured, when activated, to inhibit movement of the first and second heaters in a first direction into the well, and wherein the movement control mechanism is configured, when activated, to inhibit movement of the first and second heaters in a second direction out of the well.

1425. The system of claim 1424, wherein the movement control mechanism comprises a two-way slip mechanism.

1426. A method of producing hydrogen, comprising:

heating a subsurface formation using an in situ heat treatment process;

producing fluid from the heated formation; and

gasifying at least a portion of the fluid stream to produce hydrogen.

1427. The method of claim 1426, wherein gasifying comprises heating the formation fluid in the presence of a catalyst to produce the hydrogen stream.

1428. The method of claim 1426, wherein gasifying comprises heating the formation fluid in the presence of a catalyst and steam to produce the hydrogen stream.

1429. The method of claim 1426, further comprising introducing the hydrogen into the subsurface.

1430. The method of claim 1426, wherein the hydrogen stream comprises carbon dioxide and the method further comprises separating the carbon dioxide from the gas stream and sequestering the carbon dioxide in a portion of the subsurface formation.

1431. A method for making coiled tubing and transporting such coiled tubing to a well, comprising:

making coiled tubing at a coiled tubing manufacturing site coupled to a coiled tubing transportation system, wherein the coiled tubing transportation system is coupled to one or more movable well drilling rigs; and

using the coiled tubing transportation system to transport coiled tubing from the tubing manufacturing site to at least one of the movable well drilling rigs.

1432. The method of claim 1431, wherein the coiled tubing has an outer diameter of greater than about four inches.

1433. The method of claim 1431, further comprising making the coiled tubing from plate metal at a coiled tubing manufacturing site.

1434. The method of claim 1431, further comprising making the coiled tubing from flat rolled steel at a coiled tubing manufacturing site.

1435. The method of claim 1431, wherein making coiled tubing at a coiled tubing manufacturing site comprises using electrical resistance welding.

1436. The method of claim 1431, further comprising:

making the coiled tubing from flat rolled steel at a coiled tubing manufacturing site; and

transporting the flat rolled steel to the coiled tubing manufacturing site in rolls having a diameter of at least fifty feet.

1437. The method of claim 1431, further comprising:

making the coiled tubing from flat rolled steel at a coiled tubing manufacturing site; and

transporting the flat rolled steel to the coiled tubing manufacturing site in rolls having a diameter of at least one hundred feet.

1438. The method of claim 1431, wherein the well is a hydrocarbon well.

1439. The method of claim 1431, wherein the coiled tubing comprises a continuous length substantially equivalent to an assessed depth of a well.

1440. The method of claim 1431, further comprising using at least some of the coiled tubing to line a well.

1441. The method of claim 1431, further comprising using at least some of the coiled tubing to drill and line a well.

1442. The method of claim 1431, further comprising providing bottom hole assemblies to a well drilling rig and/or a coiled tubing manufacturing site using a carrier system coupled to a well drilling site and/or a tubing formation site.

1443. The method of claim 1431, further comprising providing bottom hole assemblies to a well drilling rig and/or a coiled tubing manufacturing site using a carrier system coupled to a well drilling site and/or a tubing formation site, wherein the carrier system comprises a carousel.

1444. The method of claim 1431, further comprising using the coiled tubing to drill a well and using the same coiled tubing for transporting materials to and/or from the surface.

1445. The method of claim 1431, wherein coiled tubing transportation system comprises a rail system.

1446. The method of claim 1431, wherein coiled tubing transportation system comprises at least one gantry and a rail system.

1447. The method of claim 1431, wherein coiled tubing transportation system comprises a rail system running in a continuous loop around a treatment area.

1448. The method of claim 1431, wherein the coiled tubing manufacturing site is less than five kilometers from one or more of the movable well drilling rigs.

1449. The method of claim 1431, wherein the coiled tubing manufacturing site is less than ten kilometers from one or more of the movable well drilling rigs.

1450. The method of claim 1431, wherein the coiled tubing manufacturing site is less than twenty kilometers from one or more of the movable well drilling rigs.

1451. The method of claim 1431, further comprising supplying and/or removing fluids to a well drilled by one or more of the movable well drilling rigs using elongated tubulars.

1452. The method of claim 1431, further comprising providing utilities to a well drilled by one or more of the movable well drilling rigs using elongated tubulars.

1453. The method of claim 1431, further comprising positioning one or more of the movable well drilling rigs using a global positioning system.

1454. The method of claim 1431, further comprising a tracking system configured to actively assess locations of a position and/or state of one or more of the movable well drilling rigs, a coiled tubing manufacturing site, and/or an associated support system.

1455. The method of claim 1431, further comprising forming at least a portion of a rail system using a positionable rail manufacturing rig, wherein the rail system is configured to assist in transporting the coiled tubing from the coiled tubing manufacturing site to one or more of the movable well drilling rigs.

1456. The method of claim 1431, further comprising coupling a hang-off assembly to a proximal end of the coiled tubing.

1457. The method of claim 1431, further comprising coupling a bottom hole assembly to a distal end of the coiled tubing.

1458. The method of claim 1431, further comprising coupling a bottom hole assembly to a distal end of the coiled tubing, wherein the bottom hole assembly is programmable.

1459. The method of claim 1431, further comprising coupling a bottom hole assembly to a distal end of the coiled tubing, wherein the bottom hole assembly is programmable to perform one or more autonomous tasks.

1460. The method of claim 1431, further comprising coupling a bottom hole assembly to a distal end of the coiled tubing, wherein the bottom hole assembly is configurable as a bottom hole electrical connector.

1461. The method of claim 1431, further comprising forming an insulation layer on at least a portion of the coiled tubing.

1462. The method of claim 1431, further comprising forming an insulation layer on at least a portion of the coiled tubing, wherein the insulation layer comprises a polymer coating.

1463. The method of claim 1431, further comprising forming an insulation layer on at least a portion of the coiled tubing, wherein the insulation layer comprises a polymer coating, and wherein the polymer coating comprises polyvinylchloride, high density polyethylene, and/or polystyrene.

1464. The method of claim 1431, further comprising forming an insulation layer on at least a portion of the coiled tubing at the coiled tubing manufacturing site.

1465. The method of claim 1431, further comprising forming an insulation layer on at least a portion of the coiled tubing at the movable well drilling rig.

1466. A method for making coiled tubing, comprising:

assessing properties of at least a first portion of a treatment area;

making coiled tubing at a coiled tubing manufacturing site based on, at least in part, the assessed properties of the first portion of the treatment area, wherein the coiled tubing manufacturing site is coupled to the first portion of the treatment area with a coiled tubing transportation system;

transporting the coiled tubing from the coiled tubing manufacturing site to the first portion of the treatment area using a coiled tubing transportation system; and

drilling a first well using a movable drilling rig and the coiled tubing.

1467. A method for making coiled tubing and transporting such coiled tubing to a well, comprising:

drilling at least a portion of a well in a treatment area;

assessing properties of the well;

making coiled tubing at a coiled tubing manufacturing site based on, at least in part, the assessed properties of the well, wherein the coiled tubing manufacturing site is coupled to the well with a coiled tubing transportation system; and

transporting the coiled tubing from the coiled tubing manufacturing site to the well using a coiled tubing transportation system.

1468. The method of claim 1467, further comprising drilling at least a portion of the well using a movable well drilling rig.

1469. A method for making coiled tubing and transporting such coiled tubing to a well, comprising:

drilling at least a portion of a first well in a treatment area;

assessing properties of the first well;

making a first coiled tubing at a coiled tubing manufacturing site based on, at least in part, the assessed properties of the first well, wherein the coiled tubing manufacturing site is coupled to the first well with a coiled tubing transportation system;

transporting the first coiled tubing from the coiled tubing manufacturing site to the first well using the coiled tubing transportation system;

drilling at least a portion of a second well in the treatment area;

assessing properties of the second well;

making a second coiled tubing at the coiled tubing manufacturing site based on, at least in part, the assessed properties of the second well, wherein the coiled tubing manufacturing site is coupled to the second well with the coiled tubing transportation system; and

transporting the second coiled tubing from the coiled tubing manufacturing site to the second well.

1470. The method of claim 1469, wherein the second coiled tubing comprises at least one property different from properties of the first coiled tubing.

1471. A system for removing protrusions from a well, comprising:

one or more cutting structures positioned along a length of a tubular in between the distal and proximal ends of the tubular, wherein the distal end of the tubular comprises a drill bit,

wherein the cutting structures are configured to remove at least a portion of one or more of protrusions positioned along at least a portion of a well.

1472. The system of claim 1471, wherein one or more of the cutting structures are directed substantially away from the distal end of the tubular in an upward manner.

1473. The system of claim 1471, wherein one or more of the cutting structures are configured to cut at least a portion of one or more of protrusions positioned along at least a portion of a well.

1474. The system of claim 1471, wherein one or more of the cutting structures are positioned on an outside portion of the tubular comprising a diameter that is greater than an average diameter of the tubular.

1475. A method for removing protrusions from a well, comprising:

removing at least a portion of one or more of protrusions positioned along at least a portion of a well using one or more cutting structures positioned along a length of a tubular in between the distal and proximal ends of the tubular.

1476. The method of claim 1475, wherein the distal end of the tubular comprises a drill bit.

1477. The method of claim 1475, wherein one or more of the cutting structures are directed substantially away from the distal end of the tubular in an upward manner.

1478. The method of claim 1475, wherein one or more of the cutting structures are configured to cut at least a portion of one or more of protrusions positioned along at least a portion of a well.

1479. The method of claim 1475, wherein one or more of the cutting structures are positioned on an outside portion of the tubular comprising a diameter that is greater than an average diameter of the tubular.

1480. A method for treating a hydrocarbon formation, comprising:

providing heat to a first portion of hydrocarbon layer in the formation from one or more heaters located in the formation;

allowing the heat to transfer from the first portion to a second portion of hydrocarbon layer in the formation;

providing a mobilization fluid to the second portion of the hydrocarbon layer to move at least some formation fluids from the second portion of the formation; and

producing at least some of the fluids from the formation.

1481. The method of claim 1480, wherein the mobilization fluid comprises water, hydrocarbons, surfactants, polymers, carbon disulfide, or mixtures thereof.

1482. The method of claim 1480, wherein the mobilization fluid comprises hydrocarbons, surfactants, polymers, carbon disulfide, or mixtures thereof.

1483. The method of claim 1480, wherein the mobilization fluid comprises hydrocarbons.

1484. The method of claim 1480, wherein the mobilization fluid comprises hydrocarbons produced from the first portion of the formation.

1485. The method of claim 1480, wherein the mobilization fluid comprises hydrocarbons produced from the first portion of the formation and wherein the hydrocarbon have a boiling range distribution from about 50 °C to about 300 °C.

1486. The method of claim 1485, wherein the naphtha comprises aromatic compounds.

1487. The method of claim 1480, wherein the mobilization fluid comprises naphtha.

1488. The method of claim 1480, wherein the produced fluids comprise formation fluids and/or mobilization fluid.

1489. A method for treating a hydrocarbon formation, comprising:

providing heat to a first portion of hydrocarbon layer in the formation from one or more heaters located in the formation;

allowing the heat to transfer from the first portion to a second portion of hydrocarbon layer in the formation;

providing a mobilization fluid to the second portion of the hydrocarbon layer to move at least some formation fluids from the second portion of the formation;

producing at least some of the fluids from the formation;

providing a pressuring fluid to the second portion of the hydrocarbon layer to move at least a portion of the fluids from the second portion of the formation; and

producing at least some of the pressured fluids from the formation.

1490. The method of claim 1489, wherein the pressuring fluid is carbon dioxide.

1491. The method of claim 1489, wherein the pressuring fluid is carbon dioxide and wherein at least a portion of the carbon dioxide is produced from the formation.

1492. The method of claim 1489, wherein the pressured fluids comprise at least a portion of the pressurizing gas, mobilization fluid, formation fluids, or mixtures thereof.

1493. The method of claim 1489, wherein the pressured fluids comprise at least a portion of the pressurizing gas and the method further comprises:

separating at least a portion of the pressurizing gas from the produced pressurized fluids; and

sequestering the pressurizing gas in a portion of the formation.

1494. The method of claim 1489, wherein the mobilization fluid comprises water, hydrocarbons, surfactants, polymers, carbon disulfide, or mixtures thereof.

1495. The method of claim 1489, wherein the mobilization fluid comprises hydrocarbons, surfactants, polymers, carbon disulfide, or mixtures thereof.

1496. The method of claim 1489, wherein the mobilization fluid comprises hydrocarbons.

1497. The method of claim 1489, wherein the mobilization fluid comprises hydrocarbons produced from the first portion of the formation.

1498. The method of claim 1489, wherein the mobilization fluid comprises hydrocarbons produced from the first portion of the formation and wherein the hydrocarbon have a boiling range distribution from about 50 °C to about 300 °C.

1499. The method of claim 1498, wherein the naphtha comprises aromatic compounds.

1500. The method of claim 1489, wherein the mobilization fluid comprises naphtha.

1501. A method for treating a hydrocarbon formation, comprising:

providing heat to a first portion of hydrocarbon layer in the formation from one or more heaters located in the formation;

allowing the heat to transfer from the first portion to a second portion and third portion of hydrocarbon layer in the formation such that at least a portion of the formation fluids in the second and at least a portion of the formation fluids in the third portion flow to the first portion; and

producing at least some of the fluids from the formation.

1502. A method for providing acidic gas to a subsurface formation, comprising:

providing heat from one or more heaters to a portion of a subsurface formation;

producing fluids from the formation using a heat treatment process, wherein the produced fluids comprise one or more sour gases; and

introducing at least a portion of one of the sour gases into the formation, or into another formation, through one or more wellbores at a pressure below a lithostatic pressure of the formation in which the sour gas is introduced.

1503. The method of claim 1502, wherein at least a portion of the sour gas comprises hydrogen sulfide and/or carbon dioxide.

1504. The method of claim 1502, wherein at least a portion of the introduced sour gas comprises hydrogen sulfide and the hydrogen sulfide forms a sulfide layer on the surface of the walls of the wellbores.

1505. The method of claim 1504, wherein at least one of the sour gases comprises carbon dioxide, and the method further comprising introducing the carbon dioxide into the sulfided wellbore.

1506. The method of claim 1502, wherein at least a portion of the sour gas reacts in the formation.

1507. The method of claim 1502, wherein at least a portion of the sour gas is sequestered in the formation.

1508. The method of claim 1502, wherein at least a portion of the sour gas is introduced near the bottom of a saline aquifer.

1509. The method of claim 1502, wherein at least one of the heaters is a temperature limited heater.

1510. The method of claim 1502, wherein at least one of the heaters is an electrical heater.

1511. A method for providing acidic gas to a subsurface formation, comprising:

providing heat from one or more heaters to a portion of a subsurface formation;

producing fluids from the formation using a heat treatment process, wherein the produced fluids comprise one or more acidic gases;

removing at least a portion of carbon dioxide from the acidic gases;

introducing at least a portion of the carbon dioxide into the formation, or into another formation, through one or more wellbores; and

introducing a fluid in the wellbores used for carbon dioxide introduction to inhibit corrosion in the wellbores.

1512. The method of claim 1511, wherein at least a portion of the carbon dioxide reacts in the formation.

1513. The method of claim 1511, wherein at least a portion of the carbon dioxide is sequestered in the formation.

1514. The method of claim 1511, wherein the fluid comprises one or more corrosion inhibitors.

1515. The method of claim 1511, wherein the fluid comprises one or more polymers.

1516. The method of claim 1511, wherein the fluid comprises one or more surfactants.

1517. The method of claim 1511, wherein the fluid comprises one or more hydrocarbons.

1518. The method of claim 1511, wherein the fluid comprises one or more corrosion inhibitors, one or more surfactants, one or more hydrocarbons, one or more polymers or mixtures thereof.

1519. A method of heating a subsurface formation, comprising:

supplying fuel to a plurality of oxidizers positioned in the subsurface formation, the fuel comprising a synthesis gas;

supplying an oxidant to the plurality of oxidizers;

mixing a portion of the fuel with a portion of the oxidant; and

combusting the fuel and oxidant mixture to produce heat that heats at least a portion of the subsurface formation.

1520. The method of claim 1519, wherein at least a portion of the fuel comprises hydrogen and carbon monoxide produced using an in situ conversion process.

1521. The method of claim 1519, wherein at least a portion of the fuel comprises a product produced from coal gasification.

1522. The method of claim 1519, wherein at least a portion of the fuel comprises a product produced from heavy oil gasification.

1523. The method of claim 1519, further comprising:

using hydrogen to enrich the fuel; and

stopping the use of hydrogen after combusting the fuel and oxidant mixture.

1524. The method of claim 1519, wherein the fuel comprises a mixture of natural gas and a component from the group consisting of ethane, propane, butane, and carbon monoxide.

1525. A method of heating a subsurface formation, comprising:

supplying fuel to a plurality of oxidizers positioned in the subsurface formation via a fuel conduit;

supplying an oxidant to the plurality of oxidizers;

mixing a portion of the fuel with a portion of the oxidant;

combusting the fuel and oxidant mixture to produce heat that heats at least a portion of the subsurface formation; and

decoking the fuel conduit.

1526. The method of claim 1525, wherein decoking comprises injecting steam into the fuel conduit.

1527. The method of claim 1525, wherein the decoking comprises injecting water into the fuel conduit.

1528. The method of claim 1525, wherein the decoking fluid comprises decreasing a residence time of fuel in the fuel conduit.

1529. The method of claim 1525, wherein decoking comprises pumping a pig through the fuel conduit.

1530. The method of claim 1525, wherein decoking comprises insulating a portion of the fuel conduit.

1531. The method of claim 1525, wherein insulating a portion of the fuel conduit comprises coating a portion of the fuel conduit with an insulating layer and a conductive layer.

1532. A downhole burner, comprising:

an oxidant conduit;

a fuel conduit positioned in the oxidant conduit;

an oxidizer coupled to the fuel conduit; and

an insulating sleeve positioned between the fuel conduit and the oxidizer; wherein a portion of the fluid flowing through the oxidant conduit passes between the insulating sleeve and fuel conduit to provide cooling to at least a portion of the fuel conduit that passes through the oxidizer.

1533. The burner of claim 1532 wherein the insulating sleeve at least partially surrounds the fuel conduit.

1534. The burner of claim 1532, further comprising a conductive layer surrounding the insulating sleeve.

1535. A method, comprising:

providing oxidant in an oxidant conduit to an oxidizer;

providing fuel through a fuel conduit to the oxidizer, wherein the fuel conduit is positioned in the oxidant conduit;

reacting fuel from the fuel conduit and oxidant from the oxidant conduit in the oxidizer to produce heat; and

flowing a portion of the oxidant in the oxidant conduit between an insulating sleeve and the fuel conduit to provide cooling to at least a portion of the fuel conduit passing through the oxidizer.

1536. The burner of claim 1535, wherein the insulating sleeve at least partially surrounds the fuel conduit.

1537. The burner of claim 1535, wherein a conductive layer surrounds the insulating sleeve.

1538. A method of heating a formation, comprising:

providing fuel to a plurality of oxidizers;

providing an oxidant to the plurality of oxidizers;

reacting the oxidant and fuel in the oxidizers to produce heat to heat a portion of the formation; and

reducing the amount of excess oxidant supplied to the oxidizers to less than about 50% excess oxidant by weight.

1539. The method of claim 1538, further comprising reducing the amount of excess oxidant to less than about 25%.

1540. The method of claim 1538, further comprising reducing the amount of excess oxidant to less than about 10%.

1541. A method of heating a formation, comprising:

providing a plurality of oxidizers connected in series;

providing fuel to the plurality of oxidizers via a fuel conduit;

providing an oxidant to the plurality of oxidizers via an oxidant conduit;

reacting the oxidant and fuel in the oxidizers to produce heat to heat a portion of the formation; and

reducing the oxidant supplied via the oxidant conduit when the temperature in the fuel conduit reaches a specified temperature.

1542. The method of claim 1541, further comprising permitting unburned material to be oxidized in the oxidant conduit.

1543. The method of claim 1541, wherein the specified temperature is about 1200 °F.

1544. The method of claim 1541, wherein the specified temperature is about 1400 °F.

1545. The method of claim 1541, wherein the specified temperature is about 1800 °F.

1546. A method of heating a formation, comprising:

providing a plurality of oxidizers comprising:

a first oxidizer;

one or more intermediate oxidizers connected in series; and

a last oxidizer;

providing fuel to the plurality of oxidizers via a fuel conduit;

providing an oxidant to the plurality of oxidizers via an oxidant conduit;

reacting the oxidant and fuel in the oxidizers to produce heat to heat a portion of the formation; and

reducing the oxidant supplied via the oxidant conduit so that the amount of oxygen in the oxidant supplied to the last oxidizer is minimized.

1547. A gas burner, comprising:

an oxidant conduit;

a fuel conduit positioned in the oxidant conduit; and

an oxidizer configured to react fuel from the fuel conduit and oxidant from the oxidant conduit to produce heat, wherein the operating temperature of the oxidizer is configured to produce less than about 10 parts per million by weight of NO_x from the gas burner.

1548. The gas burner of claim 1547, wherein the operating temperature of the oxidizer is configured by adding water to the fuel conduit.

1549. The gas burner of claim 1547, wherein the operating temperature of the oxidizer is configured by arranging openings in the oxidant conduit.

1550. A method of heating a formation comprising:

providing oxidant in an oxidant conduit to an oxidizer;

providing fuel to the oxidizer;

reacting fuel and oxidant to produce heat, wherein at least a portion of the heat transfers to the formation; and

controlling flow of fuel and oxidant to produce less than about 10 parts per million by weight of NO_x from the gas burner.

1551. The method of claim 1550, further comprising mixing water with the fuel.

1552. The method of claim 1550, further comprising arranging openings in the oxidant conduit.

1553. A method of initiating heating in a gas burner assembly in a formation, comprising:

supplying fuel through a fuel conduit in the formation, and oxidant through an oxidant conduit to provide a first combustible mixture to a last oxidizer of a plurality of oxidizers;

initiating combustion in the last oxidizer of the plurality of oxidizers to provide an ignited oxidizer;

adjusting the supply of oxidant through the oxidant conduit to supply a second-to-last oxidizer next to the ignited oxidizer with a second combustible mixture while maintaining ignition of the ignited oxidizer; and

initiating combustion in the second-to-last oxidizer.

1554. The method of claim 1553, repeating adjusting the supply of oxidant to provide a combustible fuel and oxidant mixture to the next unignited oxidizer and initiating combustion in the unignited oxidizer until all oxidizers of the plurality of oxidizers are ignited.

1555. The method of claim 1553, wherein the fuel pressure is greater than the oxidant pressure at an oxidizer before initiating combustion in the oxidizer.

1556. The method of claim 1553, wherein the fuel comprises hydrogen.

1557. The method of claim 1556, wherein at least a portion of the hydrogen is produced using an in situ conversion process.

1558. The method of claim 1556, wherein at least a portion of the hydrogen is produced using a coal gasification process.

1559. A method of initiating heating in a gas burner assembly in a formation, comprising:

supplying fuel through a fuel conduit in the formation, and oxidant through an oxidant conduit to provide a first combustible mixture to a first oxidizer of a plurality of oxidizers;

initiating combustion in the last oxidizer of the plurality of oxidizers to provide an ignited oxidizer;

adjusting the supply of oxidant through the oxidant conduit to supply a second oxidizer next to the ignited oxidizer with a second combustible mixture while maintaining ignition of the ignited oxidizer; and

initiating combustion in the second oxidizer.

1560. The method of claim 1559, further comprising repeating adjusting the supply of oxidant to provide a combustible fuel and oxidant mixture to the next unignited oxidizer and initiating combustion in the unignited oxidizer until all oxidizers of the plurality of oxidizers are ignited.

1561. The method of claim 1559, further comprising adjusting the fuel pressure by providing openings in the fuel conduit.

1562. The method of claim 1559, further comprising adjusting the fuel pressure by providing flow restrictions in the fuel conduit.

1563. A gas burner assembly for heating a subsurface formation, comprising:
an oxidant conduit;
a fuel conduit; and
a plurality of oxidizers coupled to the oxidant conduit, wherein at least one of the oxidizers comprises:
a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;
an igniter;
a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit; and
at least one flame stabilizer coupled to the shield.

1564. The assembly of claim 1563, wherein at least one flame stabilizer comprises a ring positioned in the shield downstream of a first set of openings in the shield, wherein the set of openings are radially positioned in the shield at a longitudinal distance along the shield.

1565. The assembly of claim 1564, wherein the ring is substantially perpendicular to the shield.

1566. The assembly of claim 1564, wherein the ring is angled away from the set of openings.

1567. The assembly of claim 1564, wherein the ring is angled towards the set of openings.

1568. The assembly of claim 1563, wherein the shield comprises two or more sets of openings, wherein a set of openings are radially positioned in the shield at specific longitudinal positions of the shield, and wherein flame stabilizers comprising rings are positioned between sets of openings.

1569. The assembly of claim 1563, wherein the shield comprises two or more sets of openings, wherein a set of openings are radially positioned in the shield at specific longitudinal positions of the shield, and wherein flame stabilizers comprising rings are positioned at an angle over the openings.

1570. The assembly of claim 1563, wherein at least one flame stabilizer comprises a deflection plate, wherein a portion of the deflection plate extends over an opening in the shield.

1571. The assembly of claim 1563, wherein the flame stabilizer alters the gas flow path in the shield.

1572. The assembly of claim 1563, wherein the fuel conduit is positioned in the oxidant conduit.

1573. The assembly of claim 1563, wherein fuel in the fuel conduit comprises a decoking agent.

1574. The assembly of claim 1563, further comprising a water conduit positioned in the oxidant conduit, the water conduit configured to deliver water to the fuel conduit prior to a first oxidizer.

1575. The assembly of claim 1574, wherein a portion of the water conduit passes through a heated zone generated by the first oxidizer prior to a water entry point into the fuel conduit.

1576. The assembly of claim 1563, wherein the fuel conduit is positioned in the oxidant conduit.

1577. The assembly of claim 1563, wherein the fuel conduit is positioned adjacent to one or more of the oxidizers, and wherein branches from the fuel conduit provide fuel to one or more of the oxidizers.

1578. The assembly of claim 1563, wherein the fuel conduit comprises one or more orifices to selectively control the pressure loss along the fuel conduit.

1579. A method of heating a subsurface formation, comprising:

supplying fuel to a plurality of oxidizers;

supplying oxidant to the plurality of oxidizers;

mixing a portion of the fuel with a portion of the oxidant in an oxidizer of the plurality of oxidizers to produce a combustible mixture;

reacting the combustible mixture in the oxidizer to produce a flame; and

using a flame stabilizer in the oxidizer to attach the flame to a shield.

1580. The method of claim 1579, using the flame stabilizer comprises passing gas in the oxidizer past a ring positioned in the shield.

1581. The method of claim 1580, wherein the ring is substantially perpendicular to the shield.

1582. The method of claim 1580, wherein the ring is angled in the shield.

1583. A gas burner assembly for heating a subsurface formation, comprising:

an oxidant conduit;

a fuel conduit; and

a first oxidizer coupled to the oxidant conduit, the first oxidizer comprising:

a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;

an igniter; and

a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit;

a second oxidizer coupled to the oxidant conduit, the second oxidizer comprising:

a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;

an igniter; and

a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit; and

wherein one or more of the plurality of openings of the first oxidizer are of a different size than the plurality of openings of the second oxidizer.

1584. The gas burner assembly of claim 1583, wherein at least one of the openings of the first oxidizer is of a different size than one or more other openings of the first oxidizer.

1585. A gas burner assembly for heating a subsurface formation, comprising:

an oxidant conduit;

a fuel conduit;

a first oxidizer coupled to the oxidant conduit, the first oxidizer comprising:

a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;

an igniter; and

a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit;

a second oxidizer coupled to the oxidant conduit, the second oxidizer comprising:

a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;

an igniter;

a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit; and

wherein one or more of the plurality of openings of the first oxidizer are of a different geometry than the plurality of openings of the second oxidizer.

1586. The gas burner assembly of claim 1585, wherein at least one of the openings of the first oxidizer is of a different geometry than one or more other openings of the first oxidizer.

1587. A gas burner assembly for heating a subsurface formation, comprising:

an oxidant conduit;

a fuel conduit; and

a first oxidizer coupled to the oxidant conduit, the first oxidizer comprising:

a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;

an igniter; and

a shield, wherein the shield comprises a first group of openings angled across the thickness of the shield.

1588. The gas burner assembly of claim 1587, further comprising a second group of openings not angled across the thickness of the shield.

1589. The gas burner assembly of claim 1588, wherein the first group of openings are located on a portion of the shield away from the fuel conduit.

1590. A gas burner assembly for heating a subsurface formation, comprising:

an oxidant conduit;

a fuel conduit; and

a first oxidizer coupled to the oxidant conduit, the first oxidizer comprising:

a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;

an igniter; and

a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit and a baffled section proximate to the openings.

1591. The gas burner assembly of claim 1590, further comprising a second oxidizer coupled to the oxidant conduit, the second oxidizer comprising:

a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;

an igniter; and

a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit; and

wherein one or more of the plurality of openings of the first oxidizer are of a different geometry than the plurality of openings of the second oxidizer.

1592. A gas burner assembly for heating a subsurface formation, comprising:

an oxidant conduit;

a fuel conduit; and

a plurality of oxidizers coupled to the oxidant conduit, wherein at least one of the oxidizers includes:

a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;

an igniter; and

a shield, wherein the shield comprises a plurality of louvered openings in communication with the oxidant conduit, the louvered openings configured to direct flow into the shield in a direction opposite to the direction of flow in the oxidant conduit.

1593. The assembly of claim 1592, further comprising at least one flame stabilizer, wherein at least one flame stabilizer comprises a ring positioned in the shield downstream of a first set of louvered openings in the shield, wherein the set of louvered openings are radially positioned in the shield at a longitudinal distance along the shield.

1594. The assembly of claim 1593, wherein the ring is substantially perpendicular to the shield.

1595. The assembly of claim 1593, wherein the ring is angled away from the set of louvered openings.

1596. The assembly of claim 1593, wherein the ring is angled towards the set of louvered openings.

1597. The assembly of claim 1593, wherein at least one flame stabilizer comprises a deflection plate, wherein a portion of the deflection plate extends over an opening in the shield.

1598. The assembly of claim 1592, wherein the shield comprises two or more sets of openings, wherein a set of openings are radially positioned in the shield at specific longitudinal positions of the shield, and wherein flame stabilizers comprising rings are positioned between sets of openings.

1599. The assembly of claim 1592, wherein the shield comprises two or more sets of openings, wherein a set of openings are radially positioned in the shield at specific longitudinal positions of the shield, and wherein flame stabilizers comprising rings are positioned at an angle over the openings.

1600. A method of heating a subsurface formation, comprising:

supplying fuel to a plurality of oxidizers through an oxidant conduit;

supplying oxidant to the plurality of oxidizers;

mixing a portion of the fuel with a portion of the oxidant in an oxidizer of the plurality of oxidizers to produce a combustible mixture;

reacting the combustible mixture in the oxidizer to produce a flame; and

introducing gas in the oxidant conduit into one or more of the oxidizers through louvered openings in shields of the oxidizers.

1601. The method of claim 1600, wherein the louvered openings initially direct gas from the oxidant conduit into the oxidizer in a direction opposite to the direction of flow through the oxidant conduit.

1602. The method of claim 1600, further comprising passing gas past one or more flame stabilizers in the shield of the oxidizer.

1603. A gas burner assembly for heating a subsurface formation, comprising:

an oxidant conduit;

a fuel conduit positioned in the oxidant conduit; and

a plurality of oxidizers coupled to the fuel conduit configured to react fuel from the fuel conduit and oxidant from the oxidant conduit;

wherein fuel supplied to a first oxidizer of the plurality of oxidizers is configured to pass into a heated region adjacent to the first oxidizer before entering the first oxidizer.

1604. The gas burner of claim 1603, further comprising a bypass conduit which forces fuel supplied to the first oxidizer to pass into the heated region before entering the first oxidizer.

1605. The gas burner of claim 1604, wherein the bypass conduit comprises a primary fuel hole upstream, of the first oxidizer and a secondary fuel hole inside the first oxidizer.

1606. The gas burner of claim 1603, wherein the fuel conduit is positioned in the oxidant conduit.

1607. The gas burner of claim 1603, wherein the fuel conduit is positioned adjacent to one or more of the oxidizers, and wherein branches from the fuel conduit provide fuel to one or more of the oxidizers.

1608. The gas burner of claim 1603, wherein the fuel conduit comprises one or more orifices to selectively control the pressure loss along the fuel conduit.

1609. A method for heating a subsurface formation, comprising:

providing oxidant to a plurality of oxidizers;

providing fuel to the oxidizers through a fuel conduit;

passing the fuel conduit through a heated zone adjacent to a first oxidizer before providing fuel to the first oxidizer; and

reacting fuel and oxidant to produce heat, wherein at least a portion of the heat transfers to the formation.

1610. The gas burner of claim 1609, wherein the fuel conduit is positioned in the oxidant conduit.

1611. The gas burner of claim 1609, wherein the fuel conduit is positioned adjacent to one or more of the oxidizers, and wherein branches from the fuel conduit provide fuel to one or more of the oxidizers.

1612. The gas burner of claim 1609, wherein the fuel conduit comprises one or more orifices to selectively control the pressure loss along the fuel conduit.

1613. A gas burner assembly for heating a subsurface formation, comprising:

an oxidant conduit;

a fuel conduit positioned in the oxidant conduit; and

a plurality of oxidizers coupled to the fuel conduit, wherein at least one of the oxidizers includes:

a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit; and

a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit, and wherein the fuel conduit comprises at least two fuel entries into the shield at different positions along a length of the fuel conduit.

1614. The gas burner assembly of claim 1613, wherein one of the oxidizers with the fuel conduit comprising at least two fuel entries into the shield at different positions along the length of the fuel conduit is a first oxidizer of the plurality of oxidizers.

1615. A method of heating a subsurface formation, comprising:

supplying fuel to a plurality of oxidizers through a fuel conduit;

supplying oxidant to the plurality of oxidizers through an oxidant conduit;

mixing a portion of the fuel with a portion of the oxidant in an oxidizer of the plurality of oxidizers to produce a combustible mixture; and

reacting the combustible mixture in the oxidizer to produce a flame in a shield of the oxidizer; introducing additional fuel from the fuel conduit adjacent to the shield, and introducing additional oxidant through one or more openings in the shield to provide an extended length of the flame in the oxidizer; and

heating a portion of the formation using heat generated by the flame.

1616. A gas burner assembly for heating a subsurface formation, comprising:

an oxidant conduit;

a fuel conduit; and

a plurality of oxidizers coupled to the oxidant conduit, wherein at least one of the oxidizers includes:

a mix chamber for mixing fuel from the fuel conduit with oxidant from the oxidant conduit;

a catalyst chamber containing a catalyst, the catalyst configured to react a mixture from the mix chamber to produce reaction products at a temperature that is sufficient to ignite fuel and oxidant; and

a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit.

1617. The assembly of claim 1616, wherein the shield comprises at least one flame stabilizer.

1618. The assembly of claim 1616, wherein oxidant supplied to the mix chamber comprises oxidant preheated by one or more previous oxidizers.

1619. The assembly of claim 1616, wherein the fuel conduit is positioned in the oxidant conduit.

1620. The assembly of claim 1616, wherein the fuel conduit is positioned adjacent to one or more of the oxidizers, and wherein branches from the fuel conduit provide fuel to one or more of the oxidizers.

1621. A method of heating a subsurface formation, comprising:

supplying fuel to a plurality of oxidizers;

supplying oxidant to the plurality of oxidizers;

mixing a portion of the fuel with a portion of the oxidant in an oxidizer of the plurality of oxidizers to produce a first mixture;

passing the first mixture across a catalyst to produce reaction products at a temperature sufficient to ignite fuel and oxidant; and

igniting a second mixture of fuel and oxidant to generate heat, wherein a portion of the heat is transferred to the formation.

1622. A gas burner assembly for heating a subsurface formation, comprising:

an oxidant conduit;

a fuel conduit positioned in the oxidant conduit; and

a plurality of oxidizers coupled to the fuel conduit, wherein at least one of the oxidizers includes:

a mix chamber for mixing fuel from the fuel conduit with an oxidant;

an igniter in the mix chamber configured to ignite fuel and oxidant to preheat fuel and oxidant;

a catalyst chamber containing a catalyst, the catalyst configured to react preheated fuel and oxidant from the mix chamber to produce reaction products at a temperature sufficient to ignite fuel and oxidant; and

a shield, wherein the shield comprises a plurality of openings in communication with the oxidant conduit.

1623. The assembly of claim 1622, wherein the catalyst chamber comprises one or more openings configured to allow oxidant, fuel, or a mixture thereof to contact the catalyst.

1624. The assembly of claim 1622, wherein the catalyst chamber comprises one or more openings configured to allow the reaction products to exit the catalyst chamber and contact a mixture of fuel and oxidant.

1625. The assembly of claim 1622, further comprising a water conduit positioned in the oxidant conduit, the water conduit configured to deliver water that inhibits coking of fuel to the fuel conduit before a first oxidizer in the gas burner assembly.

1626. The assembly of claim 1622, wherein the shield comprises at least one flame stabilizer.

1627. The assembly of claim 1622, wherein the igniter comprises a glow plug.

1628. The assembly of claim 1622, wherein the igniter comprises a temperature limited heating element.

1629. A method of heating a subsurface formation, comprising:

supplying fuel to a plurality of oxidizers;

supplying oxidant to the plurality of oxidizers;

mixing a portion of the fuel with a portion of the oxidant in an oxidizer of the plurality of oxidizers to produce a first mixture;

using an igniter to ignite the first mixture and produce heat;

using the heat to preheat a second mixture;

passing the preheated second mixture over a catalyst to react the mixture and produce heat; and

using the heat to ignite a third mixture of oxidant and fuel to produce a flame in the oxidizer and generate heat, wherein at least a portion of the heat transfers to the formation.

1630. The method of claim 1629, wherein the igniter comprises a temperature limited heating element.

1631. The method of claim 1629, wherein the igniter comprises a glow plug.

1632. A method of initiating heating in a gas burner assembly in a formation, comprising:

supplying fuel of a first composition through a fuel conduit in the formation, and oxidant through an oxidant conduit;

initiating combustion in an oxidizer; and

adjusting the supply and composition of fuel in the conduit to supply fuel of a second composition to the formation.

1633. The method of claim 1632, wherein the first composition comprises hydrogen.

1634. The method of claim 1632, wherein the second composition comprises natural gas.

1635. A method of initiating heating in a gas burner assembly in a formation, comprising:

supplying fuel through a fuel conduit and oxidant through an oxidant conduit;

igniting the burner using a fuel composition comprising hydrogen; and

adjusting the composition of the fuel in the fuel conduit so that the fuel comprises natural gas.

1636. A heating system for a subsurface formation, comprising:

an electrical conductor;

an insulation layer at least partially surrounding the electrical conductor; and

a jacket comprising ferromagnetic material, the jacket at least partially surrounding the insulation layer, wherein the outside surface of the jacket is configured to be at little or no

potential while the jacket is at temperatures below the Curie temperature of the ferromagnetic material.

1637. The heating system of claim 1636, wherein the jacket has a thickness of at least 2 times the skin depth of the ferromagnetic material.

1638. The heating system of claim 1636, wherein the jacket has a thickness of at least 3 times the skin depth of the ferromagnetic material.

1639. The heating system of claim 1636, wherein a majority of electrical current passes through the jacket on the inside diameter of the jacket.

1640. The heating system of claim 1636, wherein the jacket and the electrical conductor are electrically coupled at distal ends of the jacket and the electrical conductor.

1641. The heating system of claim 1636, wherein the electrical conductor is copper.

1642. The heating system of claim 1636, wherein the jacket is formed from multiple layers of material.

1643. The heating system of claim 1636, wherein a majority of the heat generated by the heating system is generated in the jacket.

1644. A heating system for a subsurface formation, comprising:

an electrical conductor;

an insulation layer at least partially surrounding the electrical conductor; and

a jacket comprising ferromagnetic material, the jacket at least partially surrounding the insulation layer, wherein the jacket is configured to generate a majority of the heat in the heating system when a time-varying electrical current is applied to the heating system.

1645. A system for a subsurface formation, comprising:

a wellbore located in the subsurface formation;

a downhole load located in the wellbore;

a transformer located in the wellbore, the transformer being electrically coupled to the downhole load, and being configured to provide power to the downhole load; and

a cooling system located in the wellbore, the cooling system being configured to maintain a temperature of the transformer below a selected temperature.

1646. The system of claim 1645, wherein the cooling system comprises a flow of cooling fluid substantially surrounding the transformer in the wellbore, wherein the cooling fluid is configured to transfer heat away from the transformer.

1647. The system of claim 1645, wherein the cooling system comprises a flow of water substantially surrounding the transformer in the wellbore, wherein the water is configured to transfer heat away from the transformer.

1648. The system of claim 1645, wherein the cooling system comprises a flow of cooling fluid in the wellbore, the transformer being immersed in the cooling fluid.

1649. The system of claim 1645, wherein the selected temperature is a maximum operating temperature of the transformer.

1650. The system of claim 1645, wherein the transformer is sealed to inhibit fluids from entering the transformer.

1651. The system of claim 1645, further comprising a packing located in the wellbore between the transformer and the downhole load, the packing being configured to inhibit fluid flow between the portion of the wellbore with the transformer and the portion of the wellbore with the downhole load.

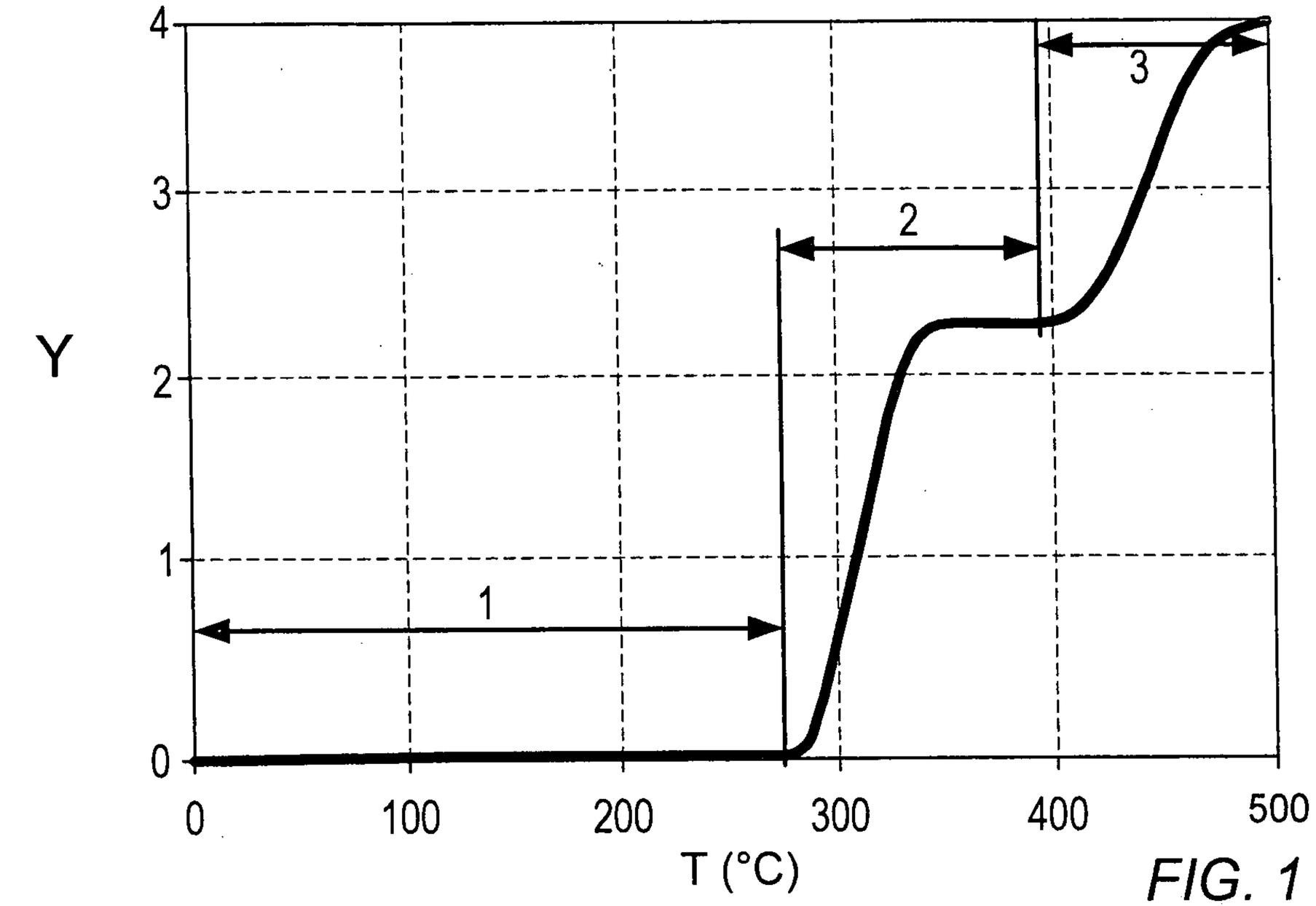

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FIG. 1

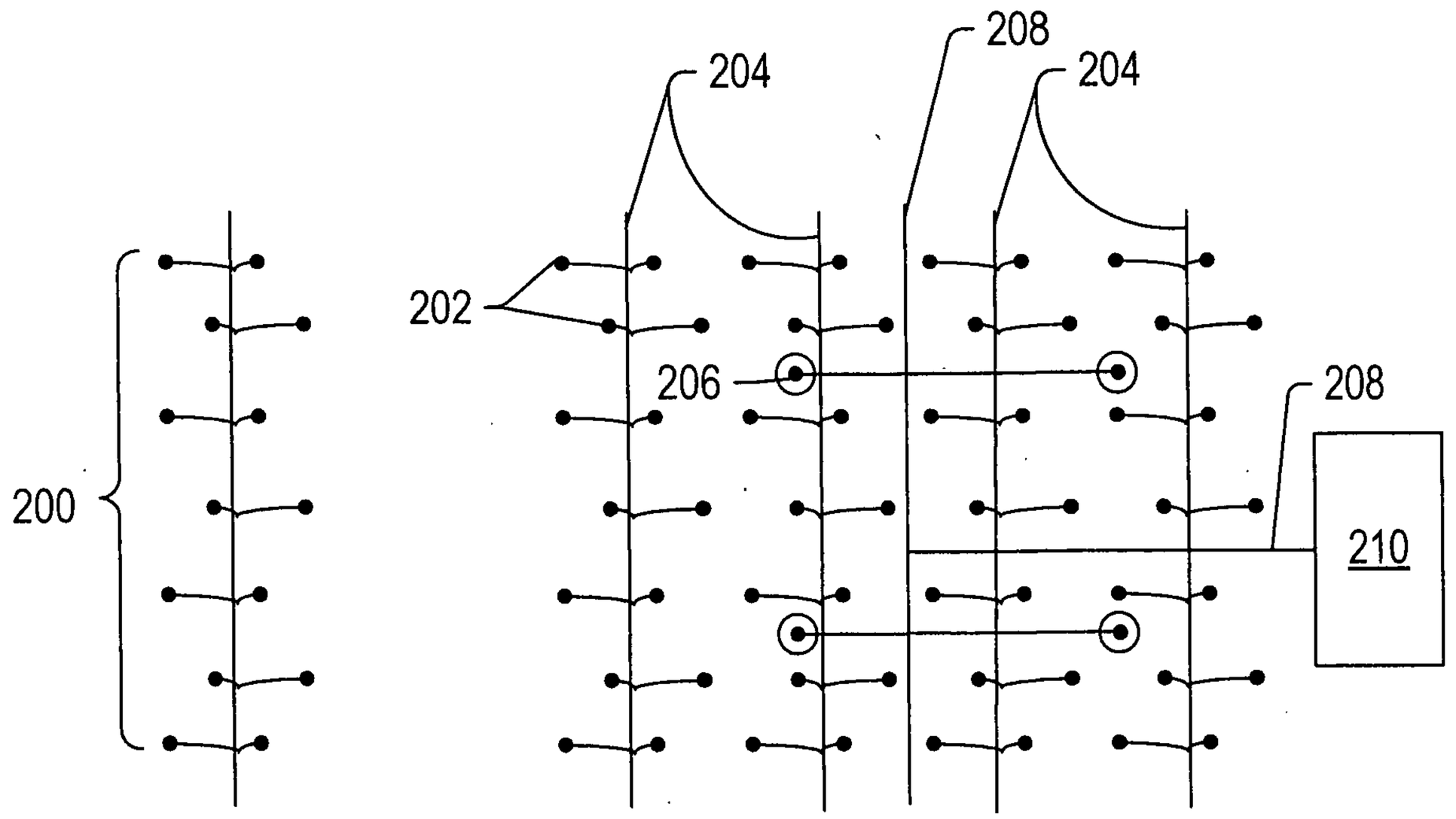

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FIG. 2

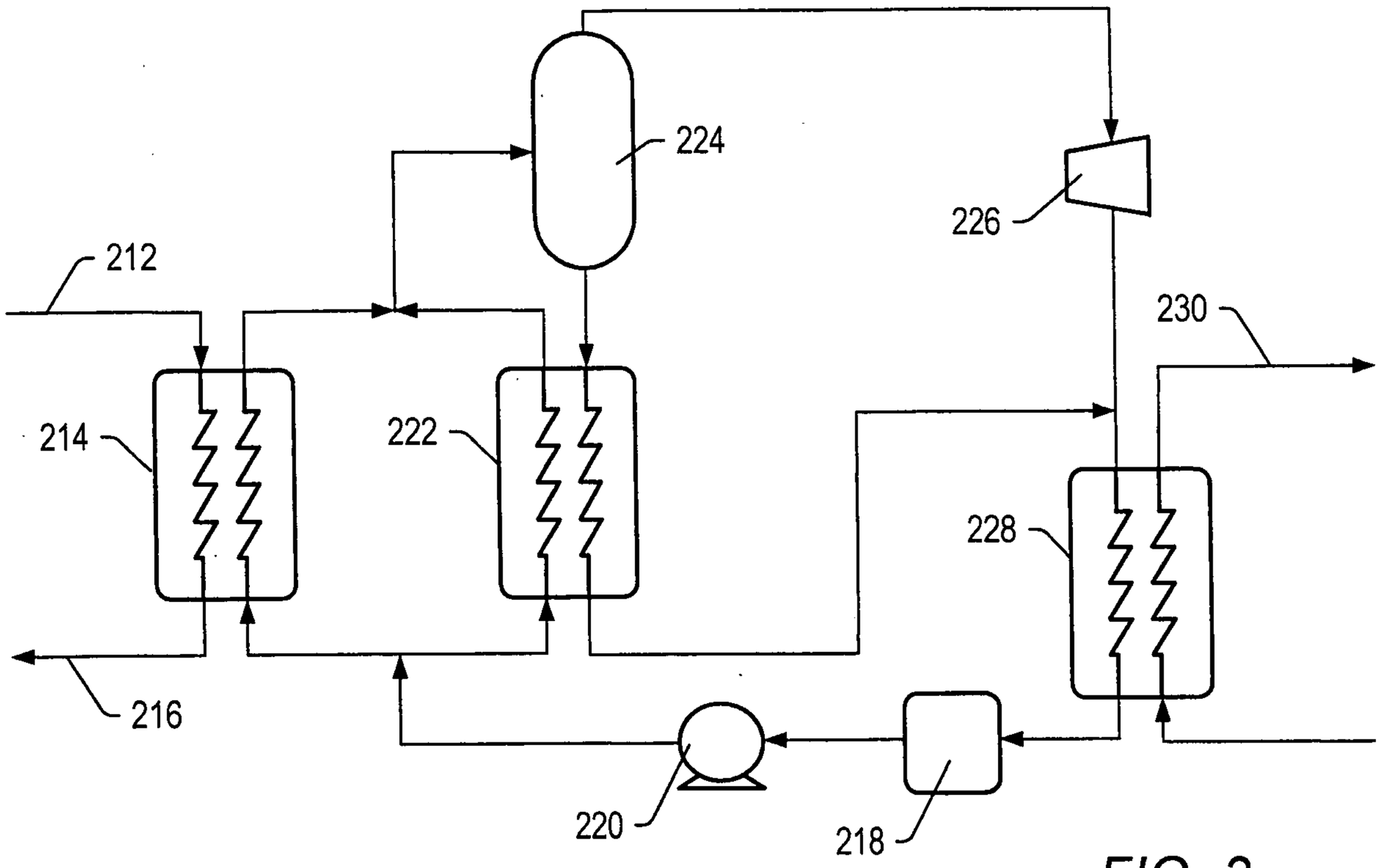

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FIG. 3

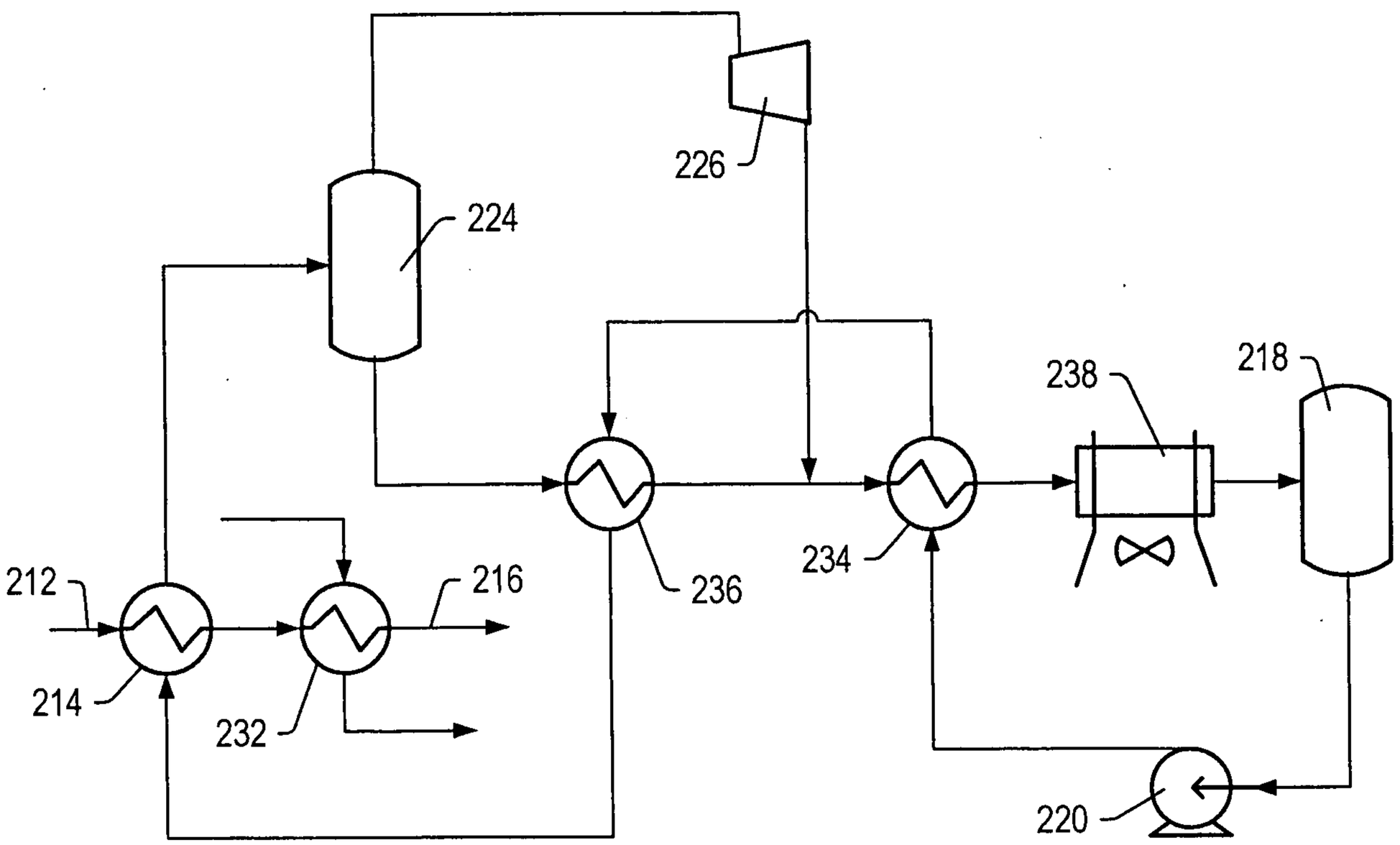

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FIG. 4

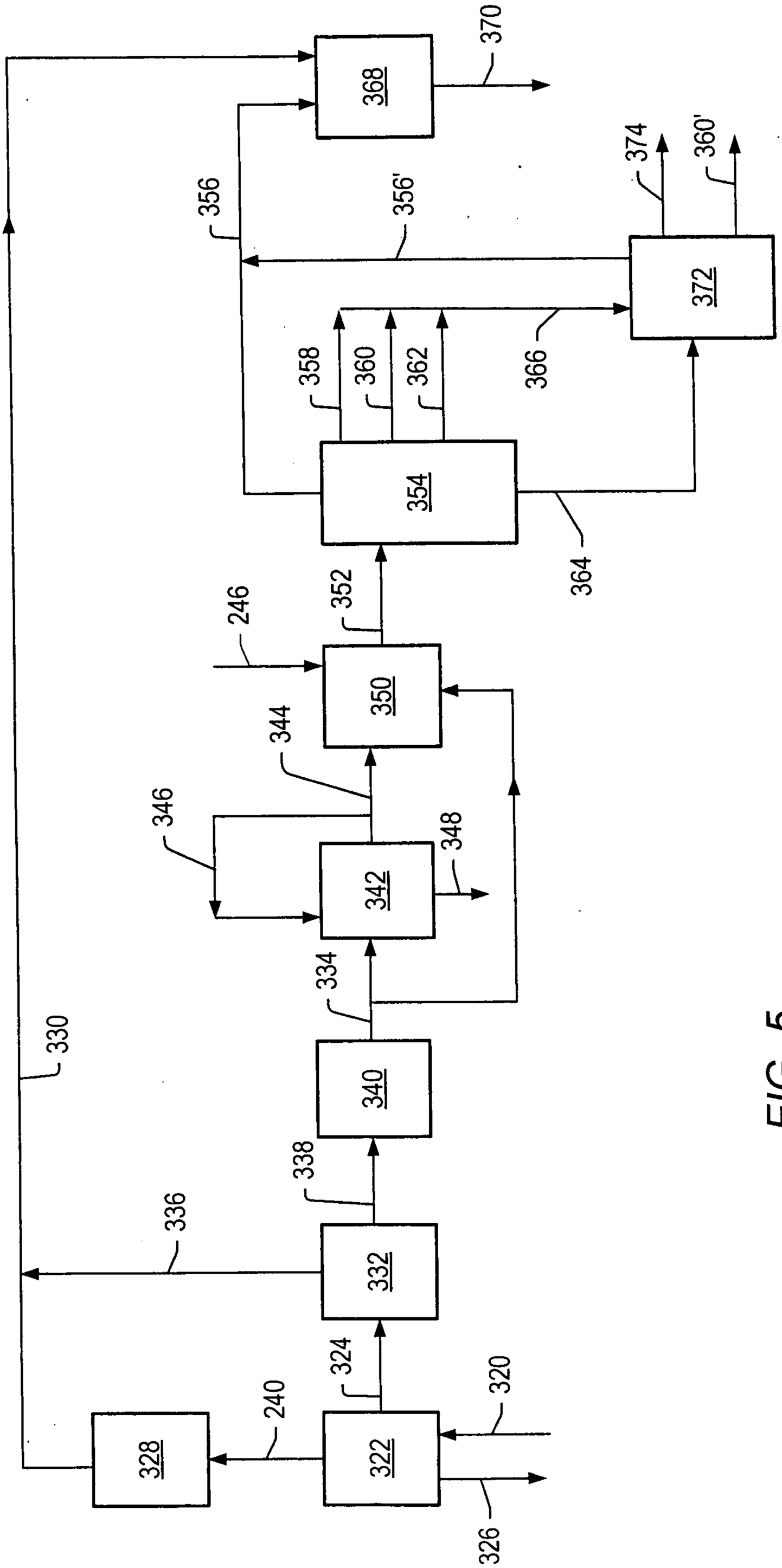

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FIG. 5

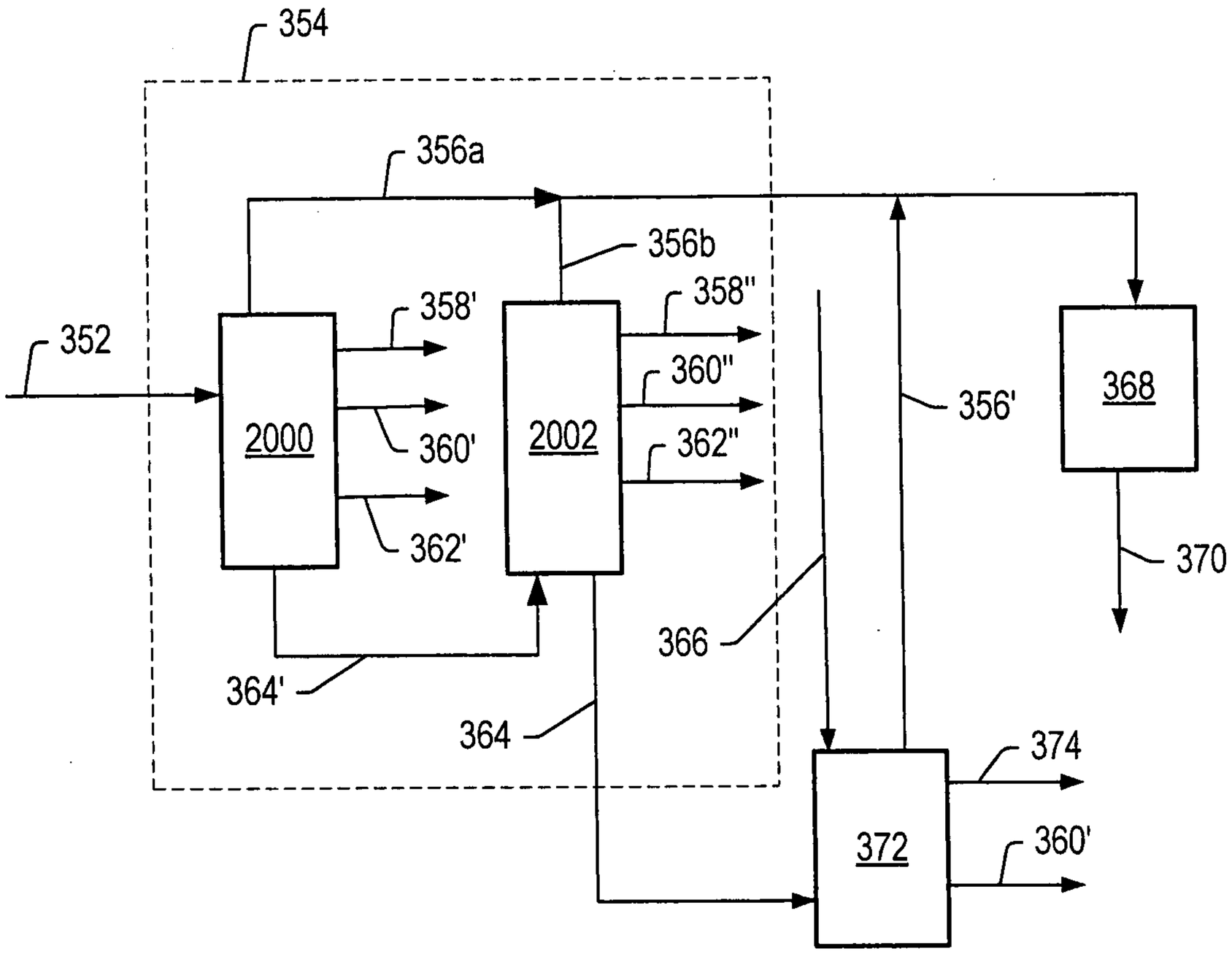

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362"
356'
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FIG. 5A

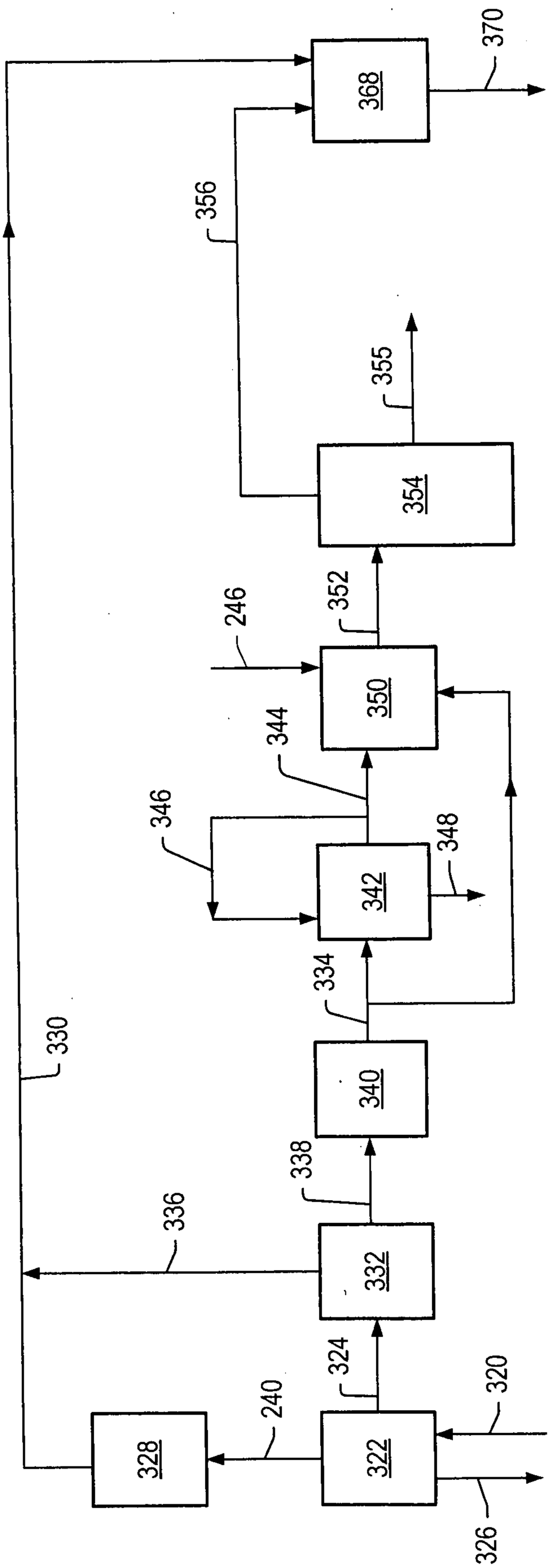

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FIG. 6

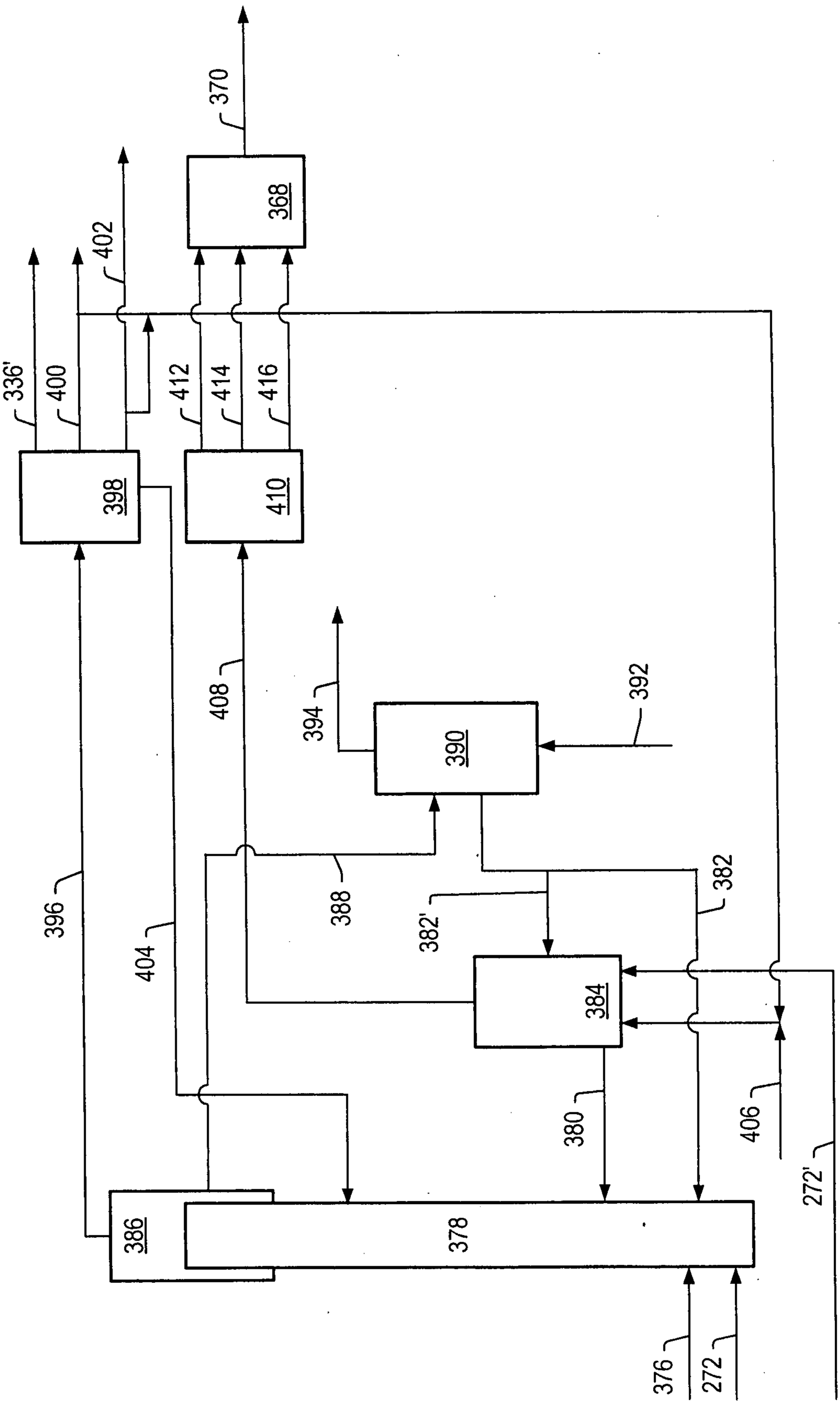

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FIG. 7

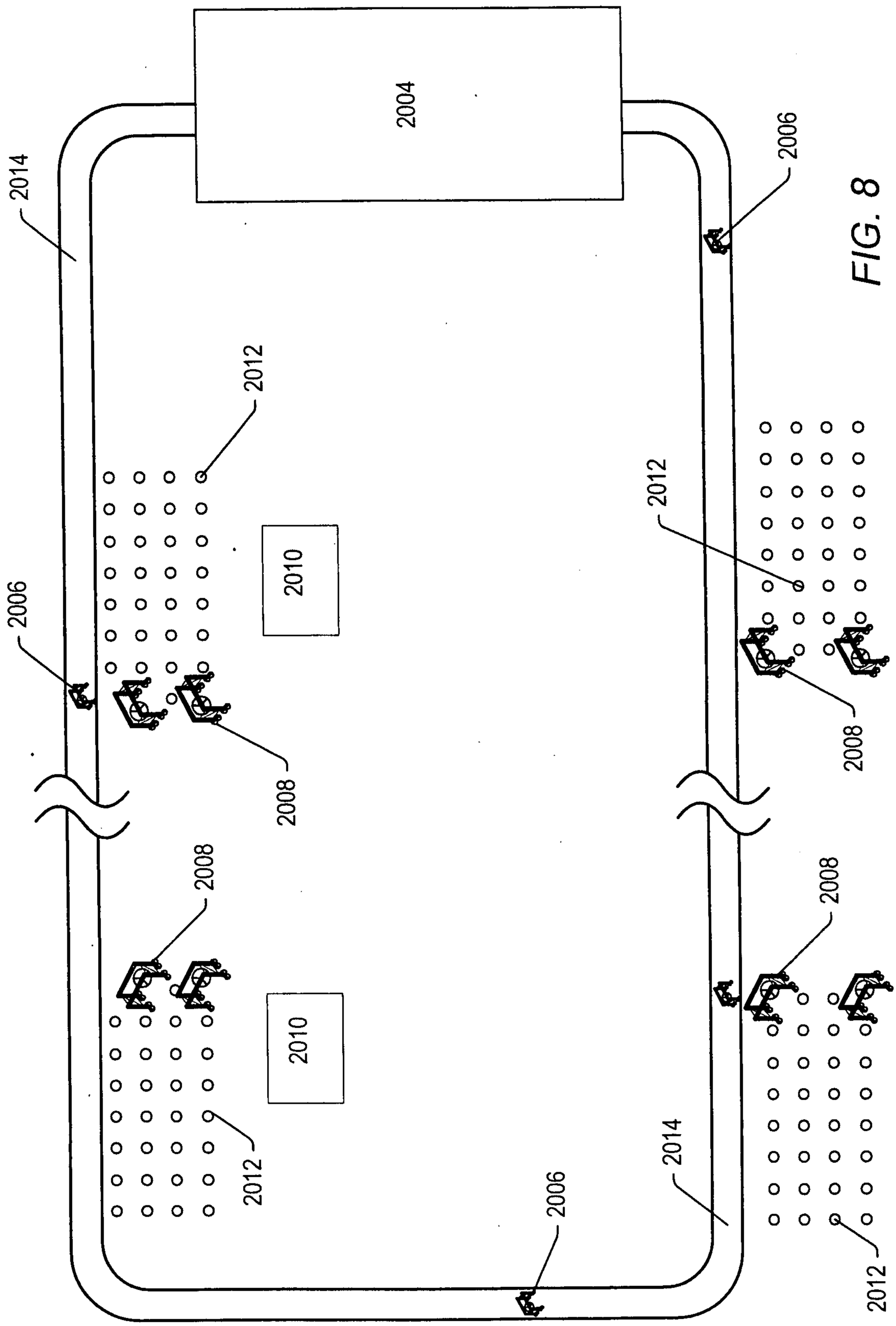

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FIG. 8

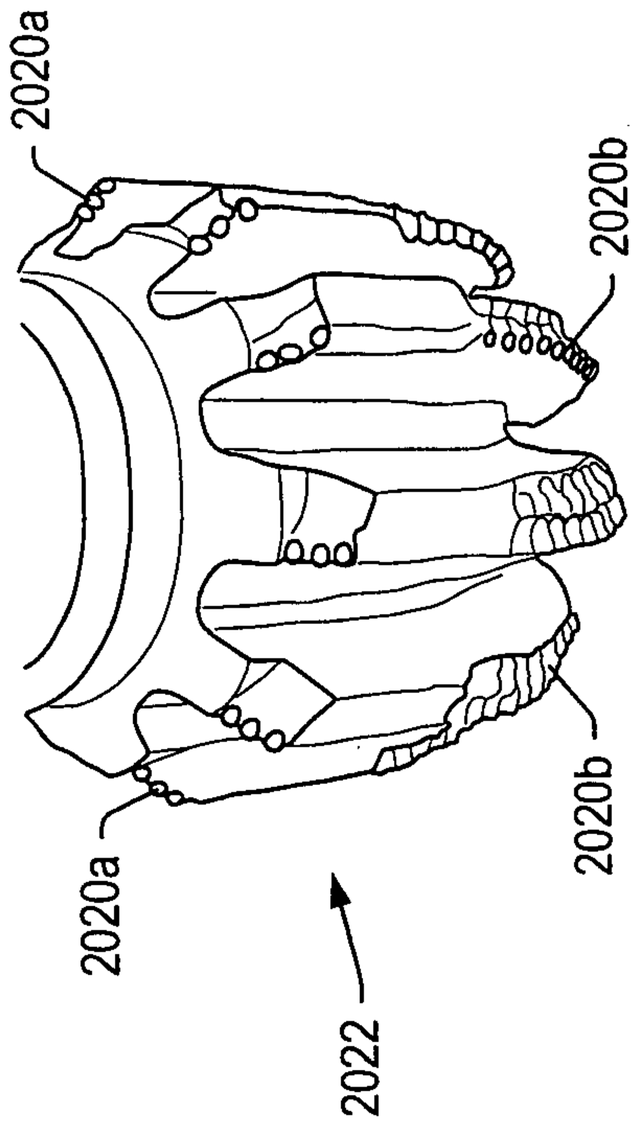


FIG. 10

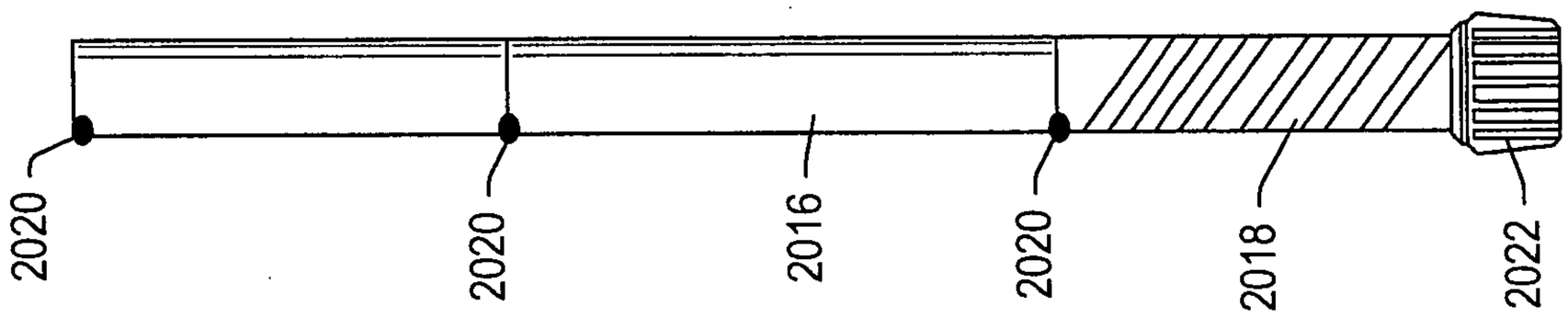


FIG. 9C

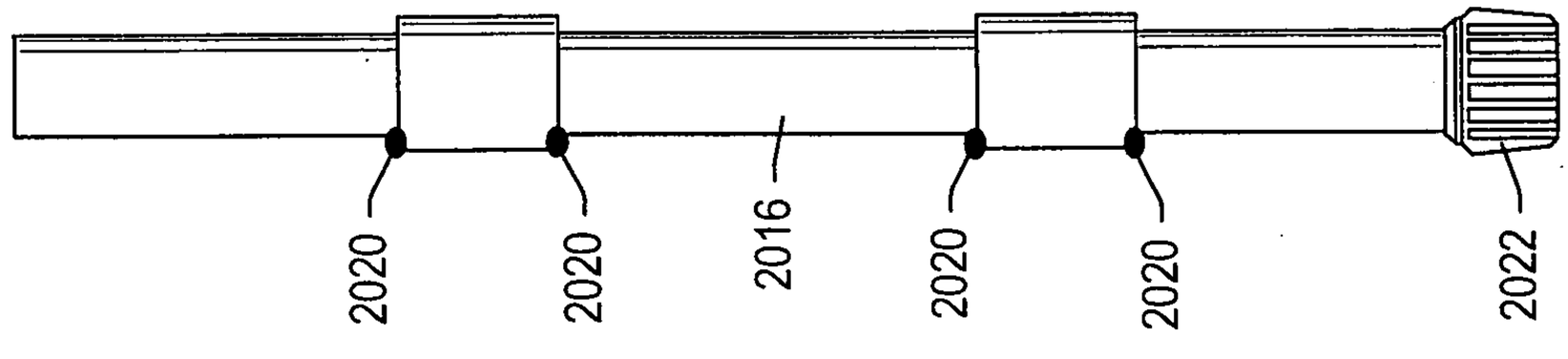


FIG. 9B

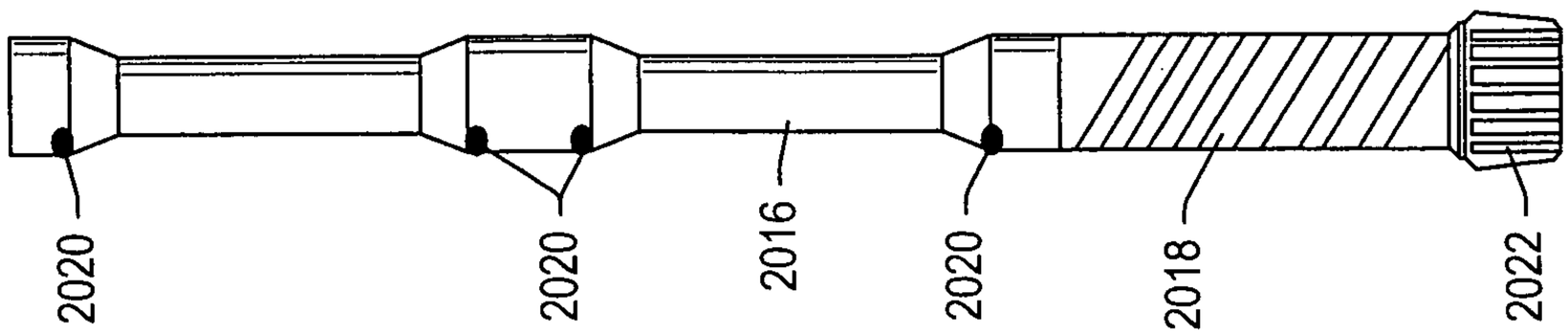


FIG. 9A

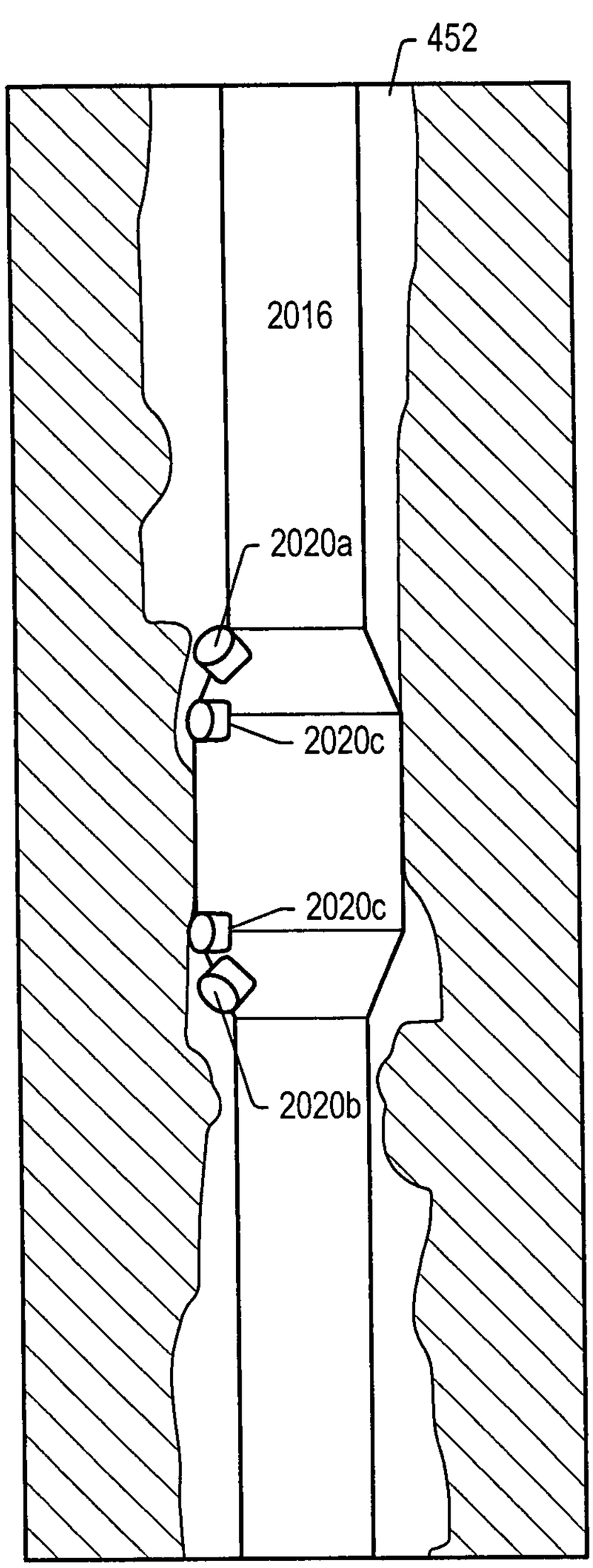


FIG. 11

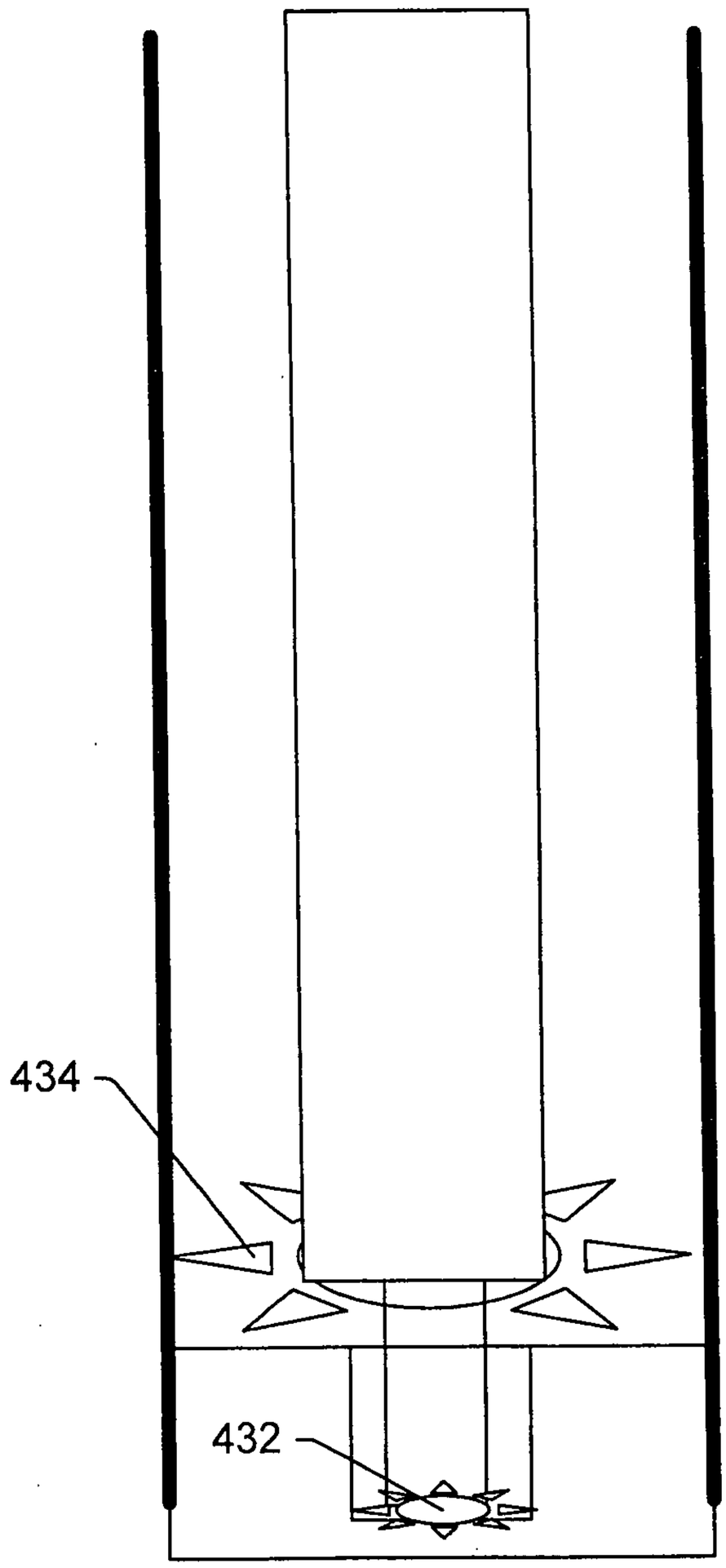


FIG. 12

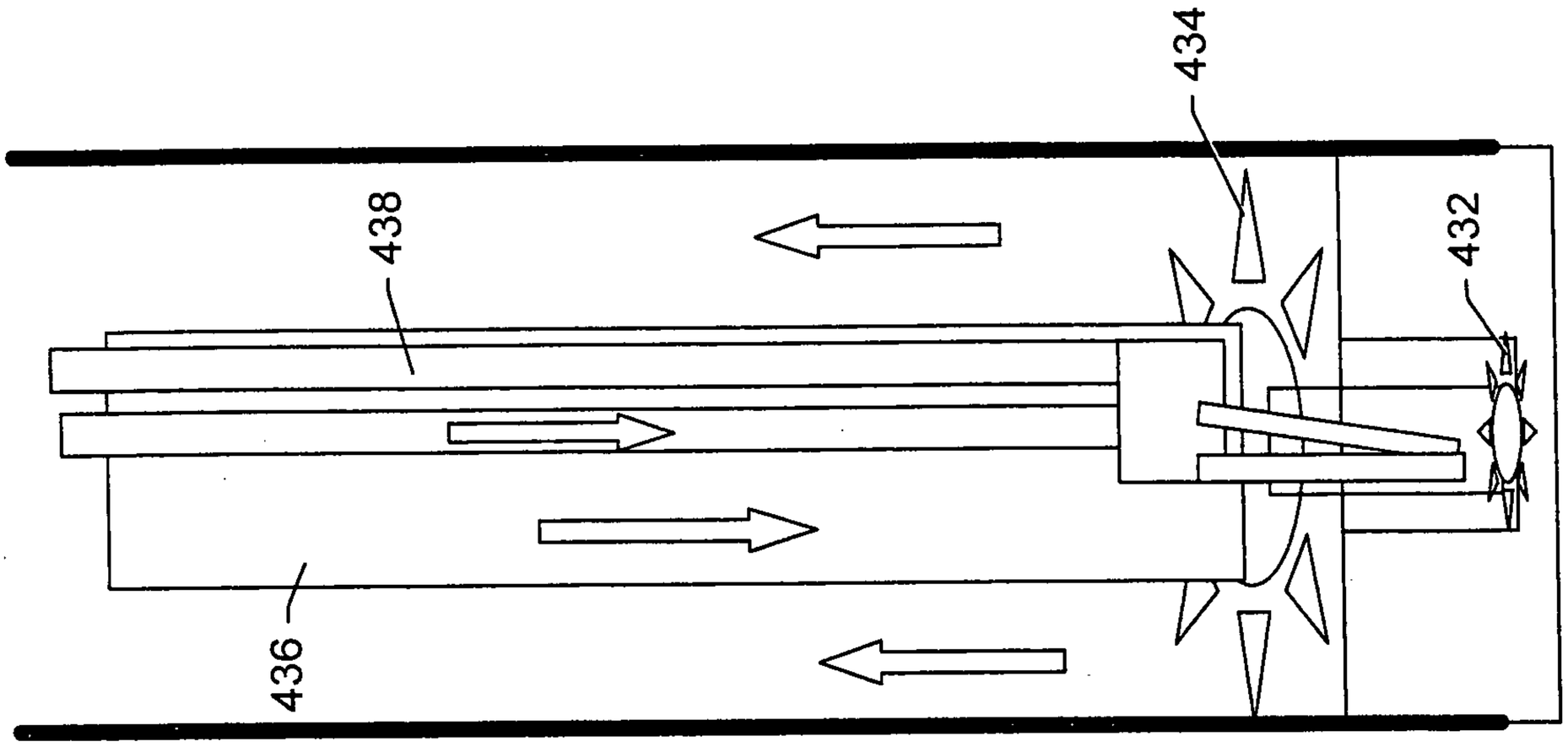


FIG. 15

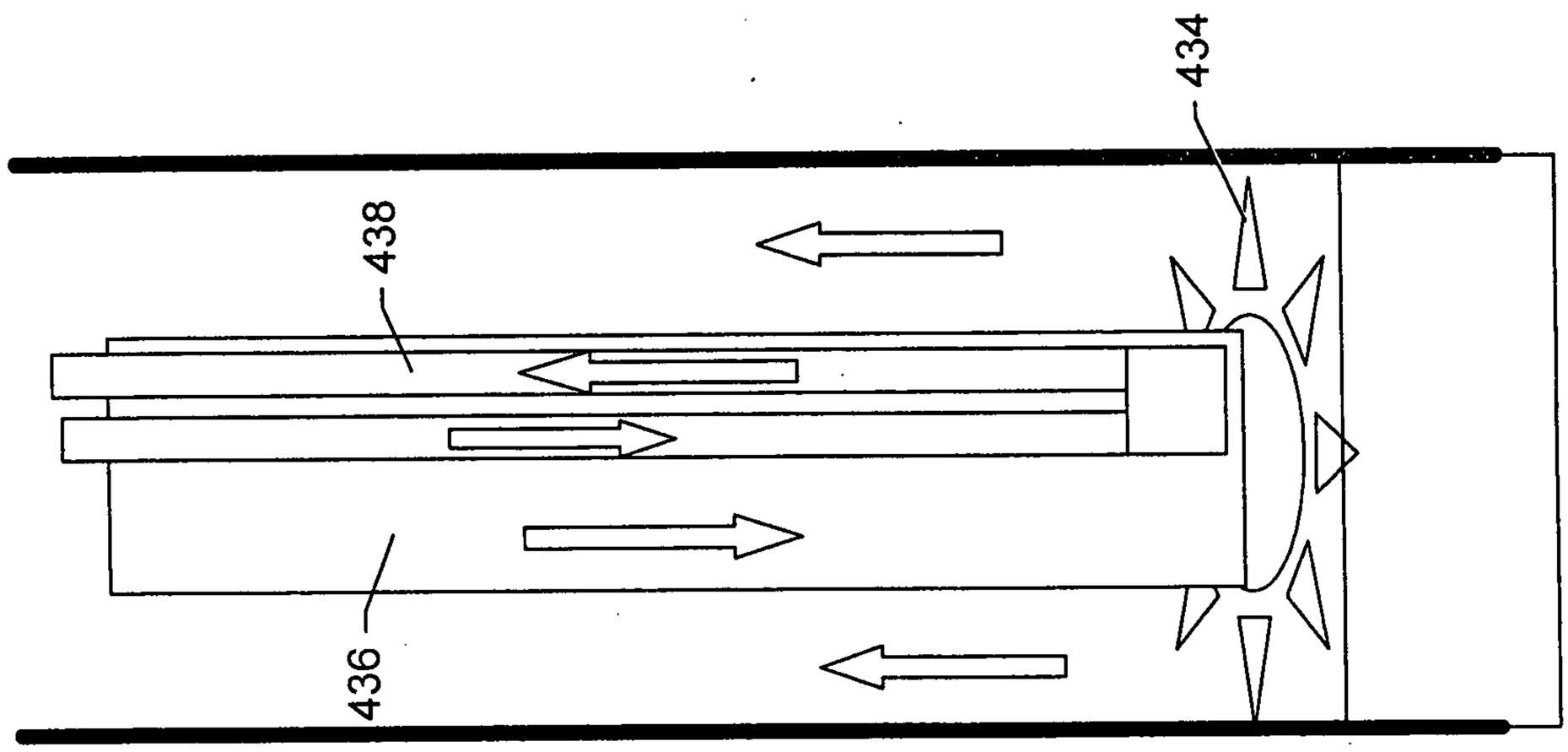


FIG. 14

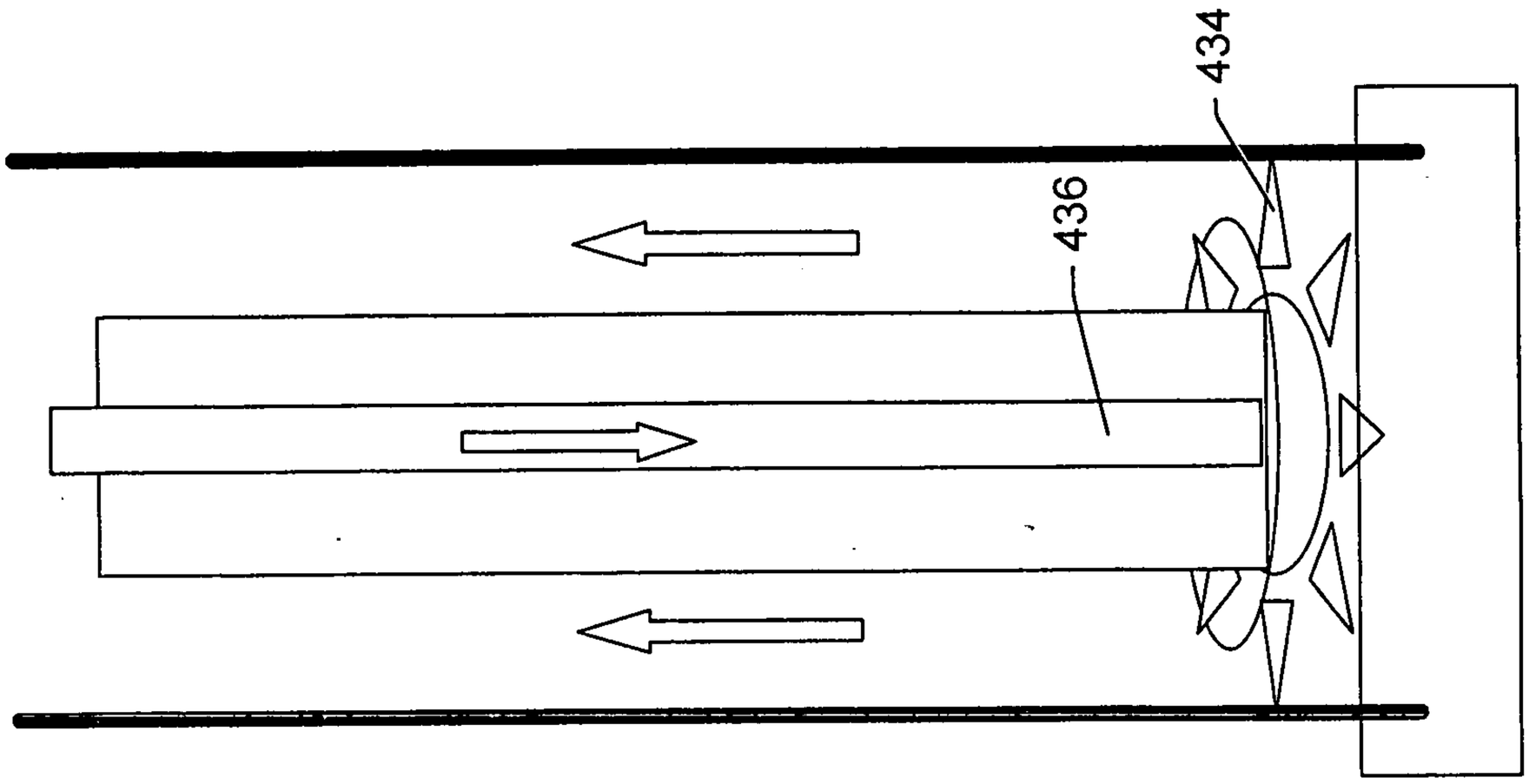


FIG. 13

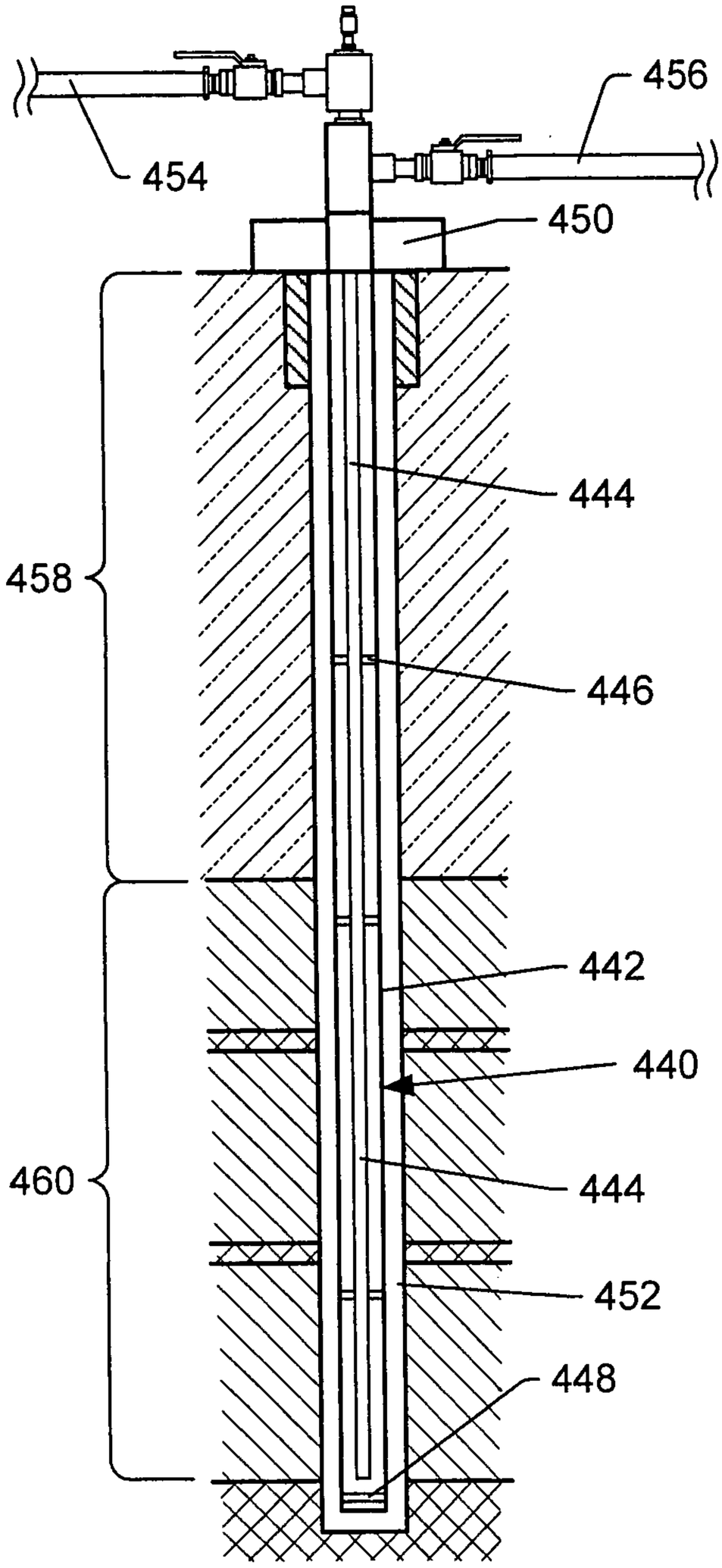


FIG. 16

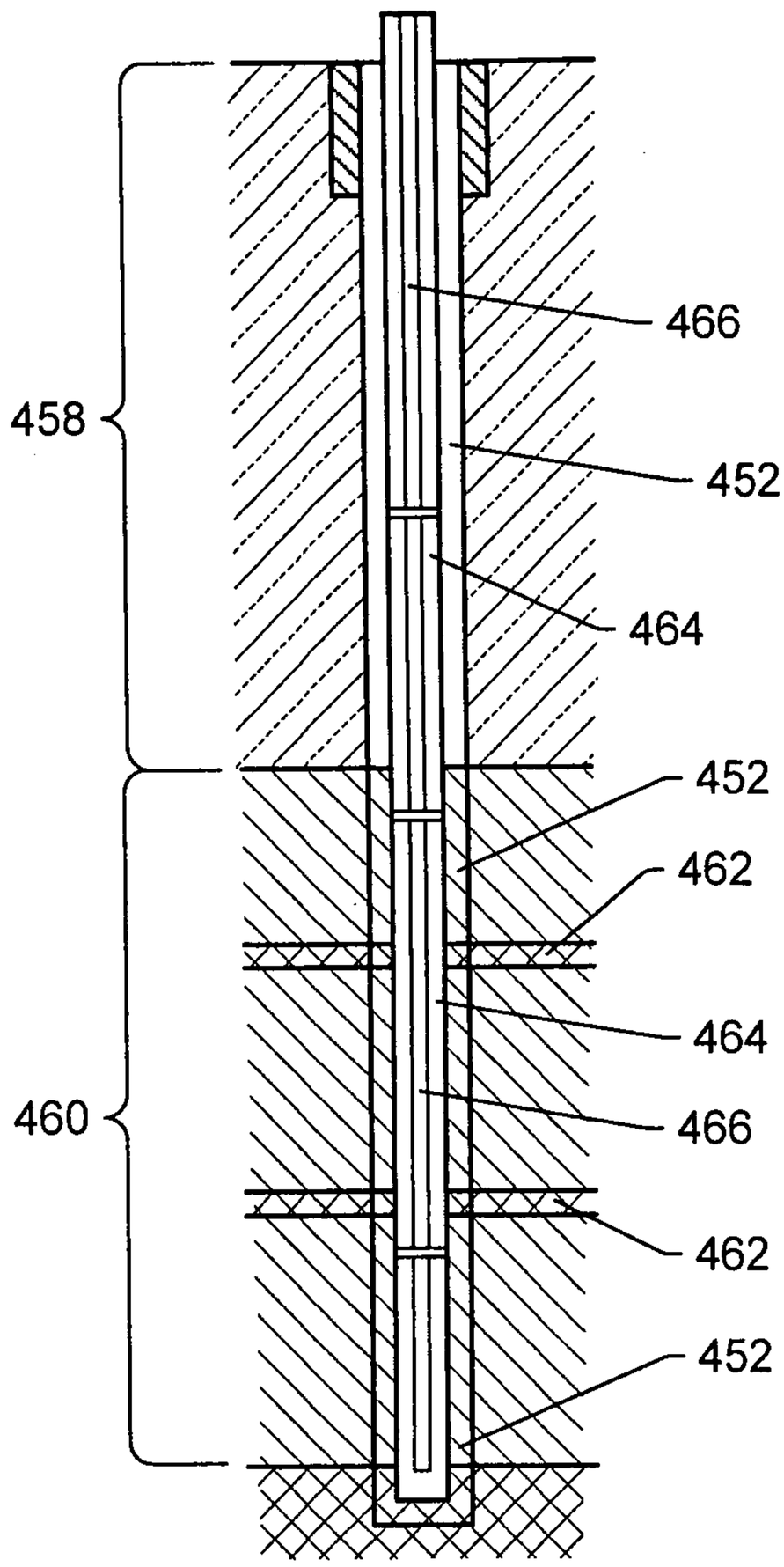


FIG. 17A

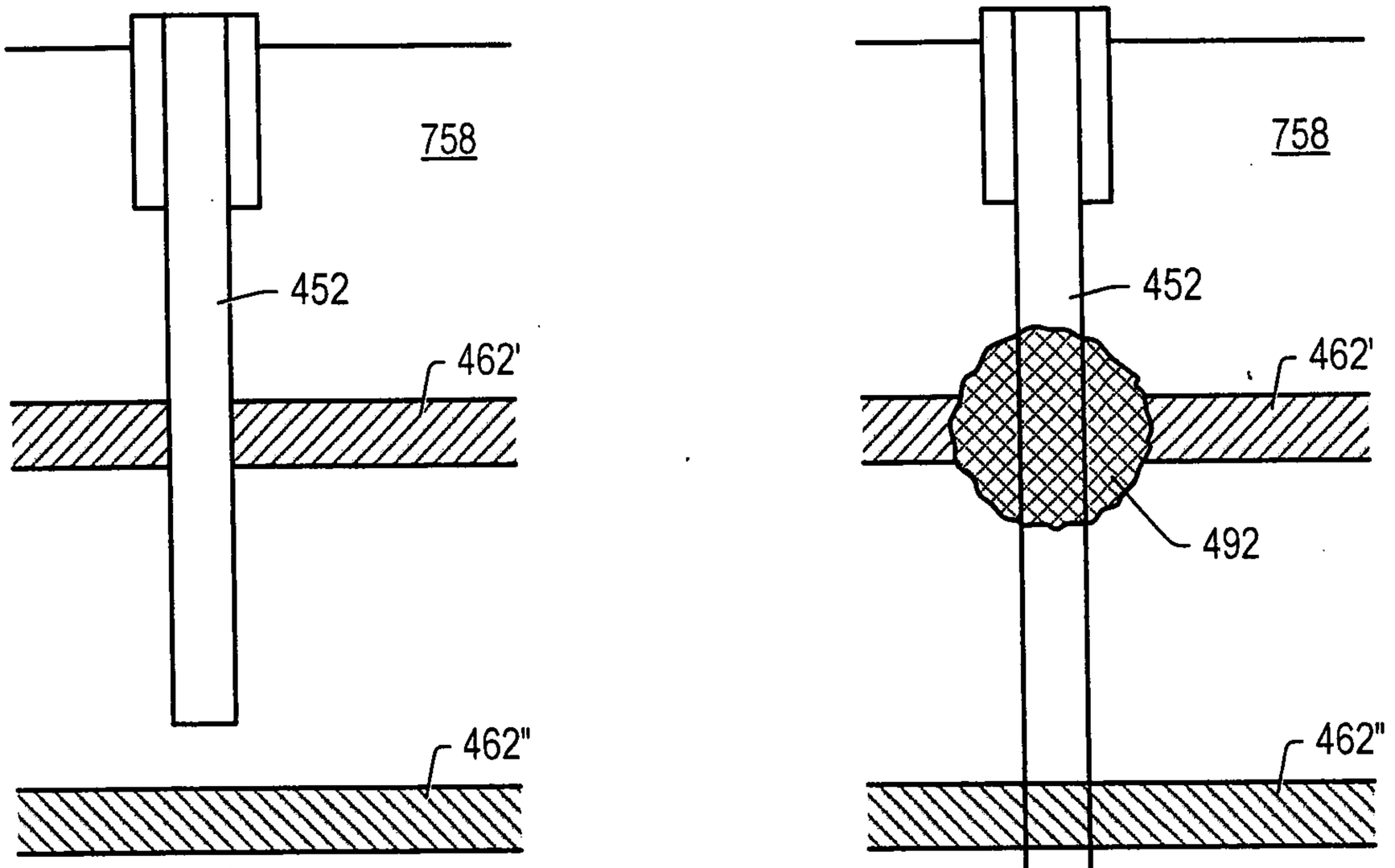


FIG. 17B

FIG. 17C

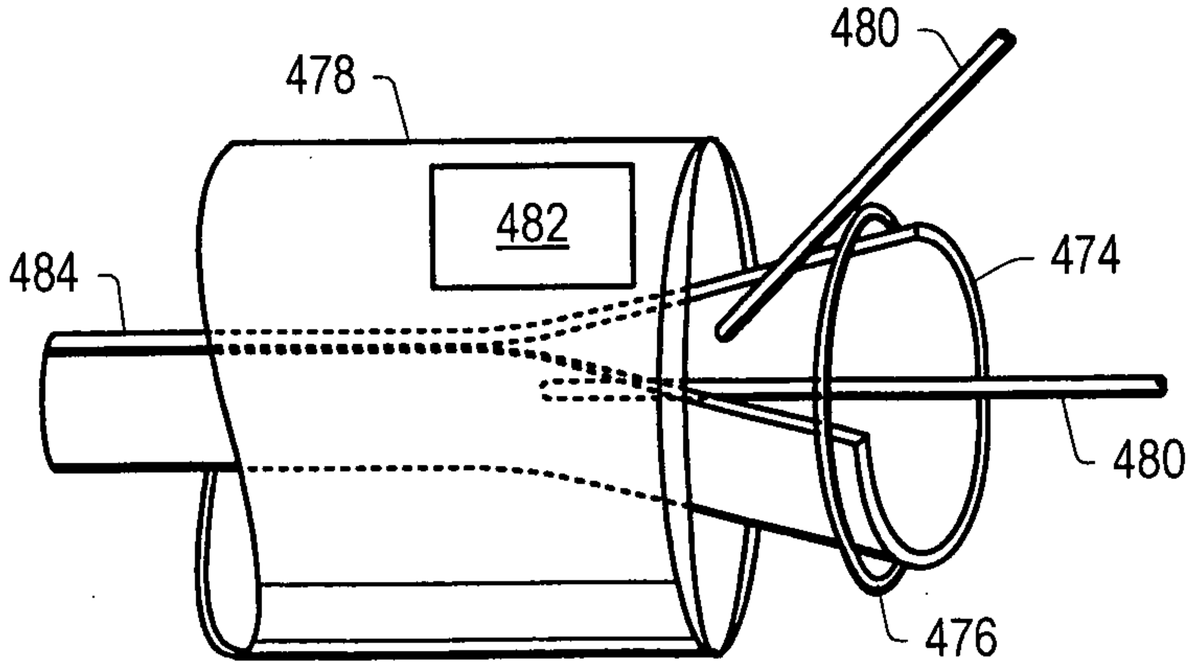


FIG. 18

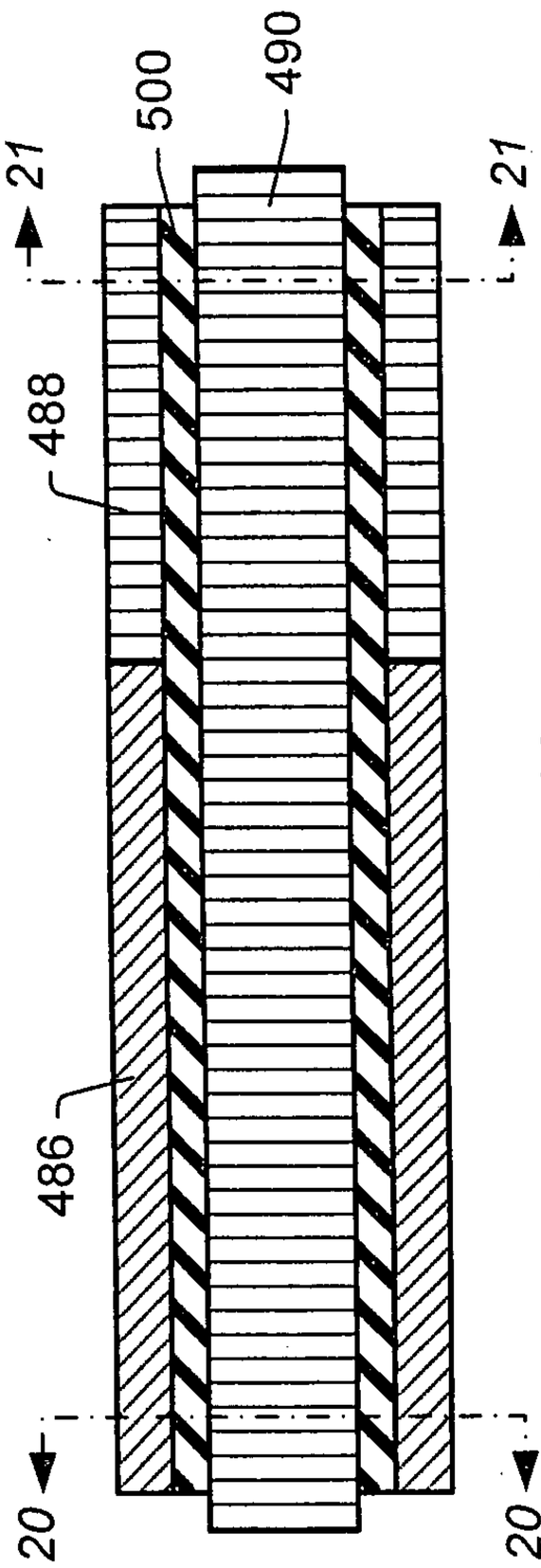


FIG. 19

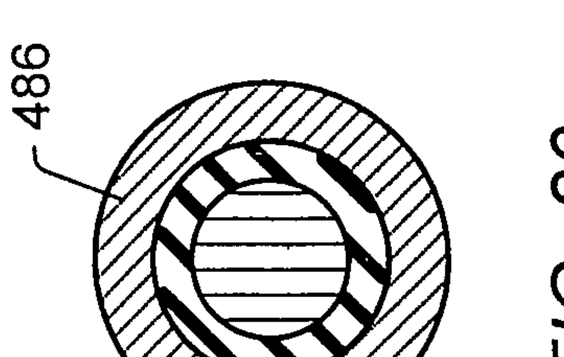


FIG. 20

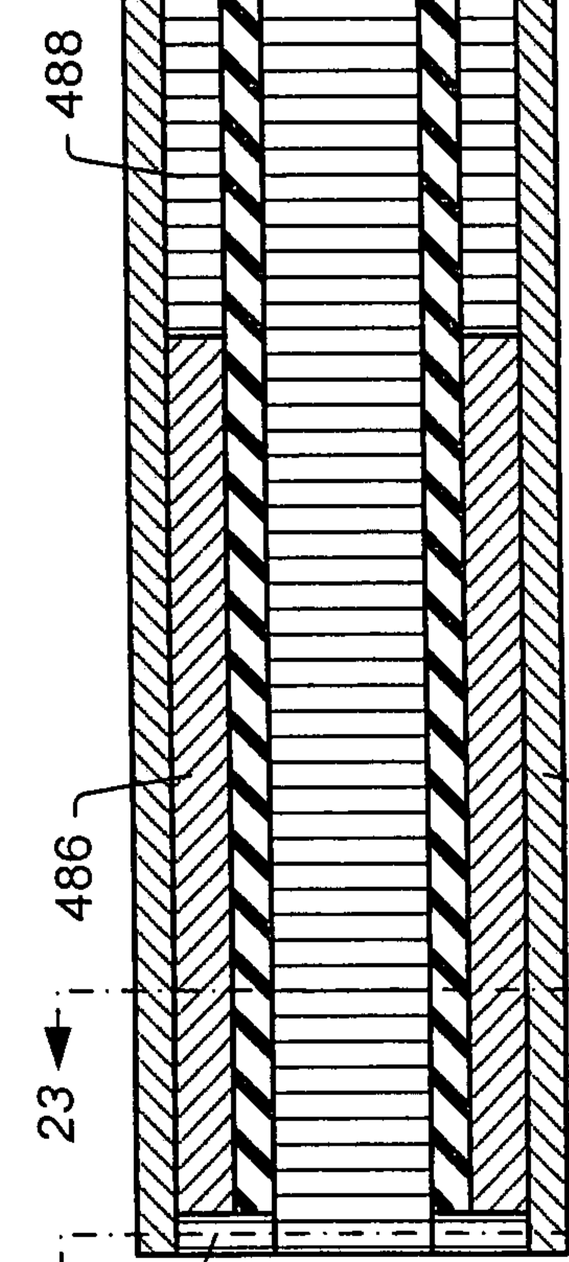


FIG. 22

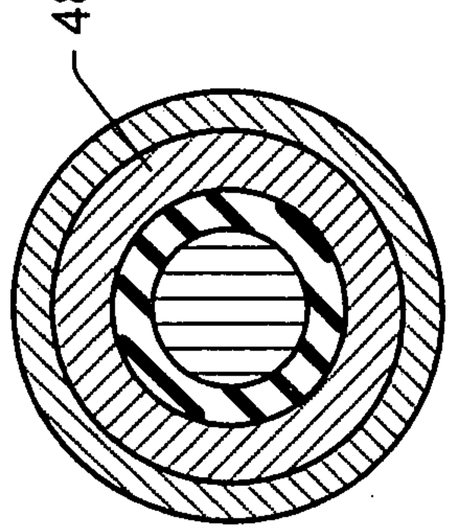


FIG. 23

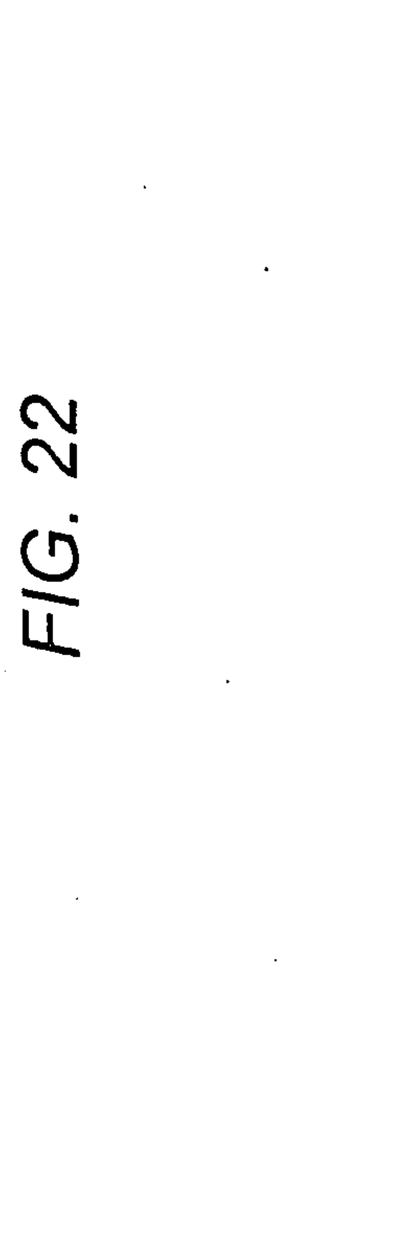


FIG. 24

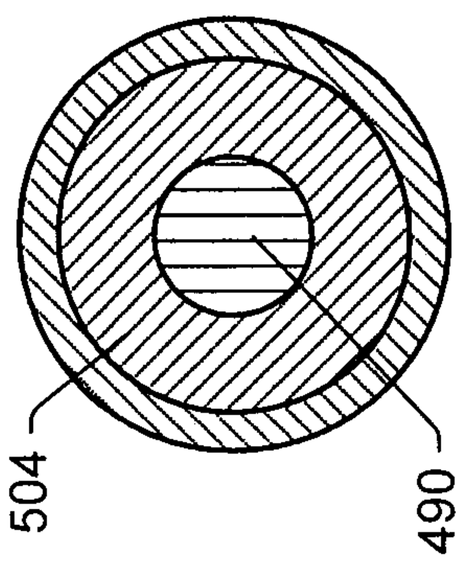


FIG. 25

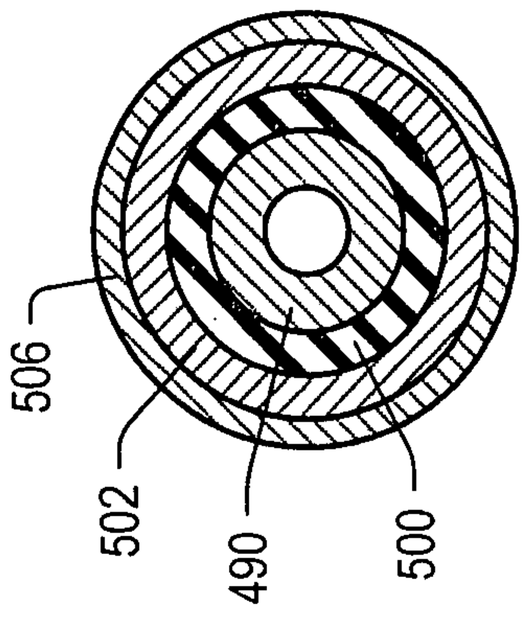


FIG. 26B

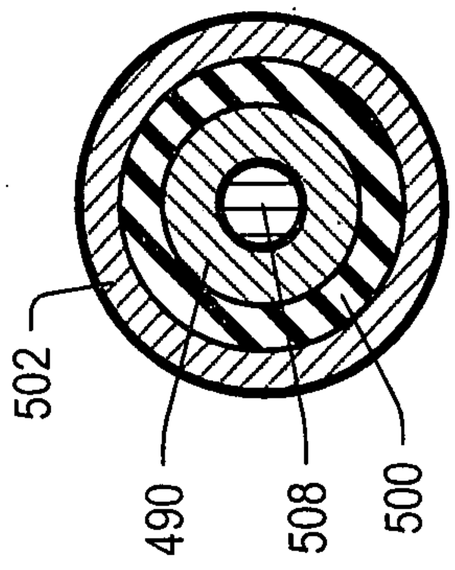


FIG. 27B

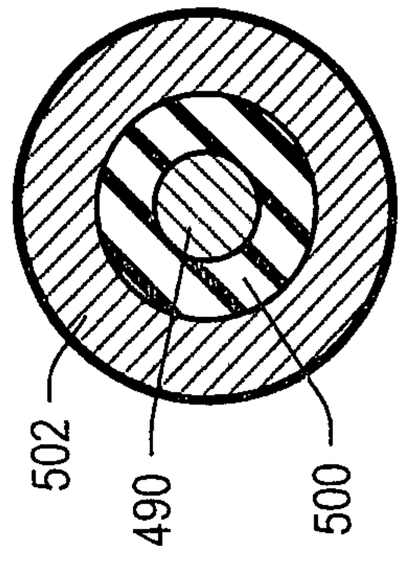


FIG. 28B

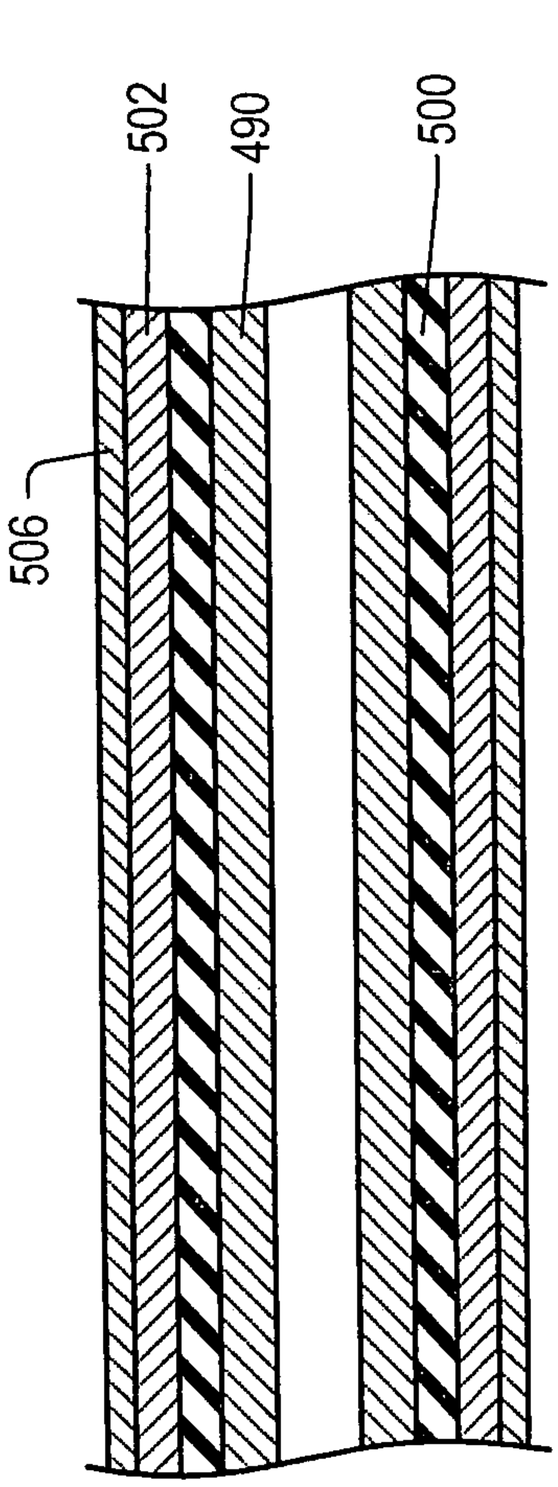


FIG. 26A

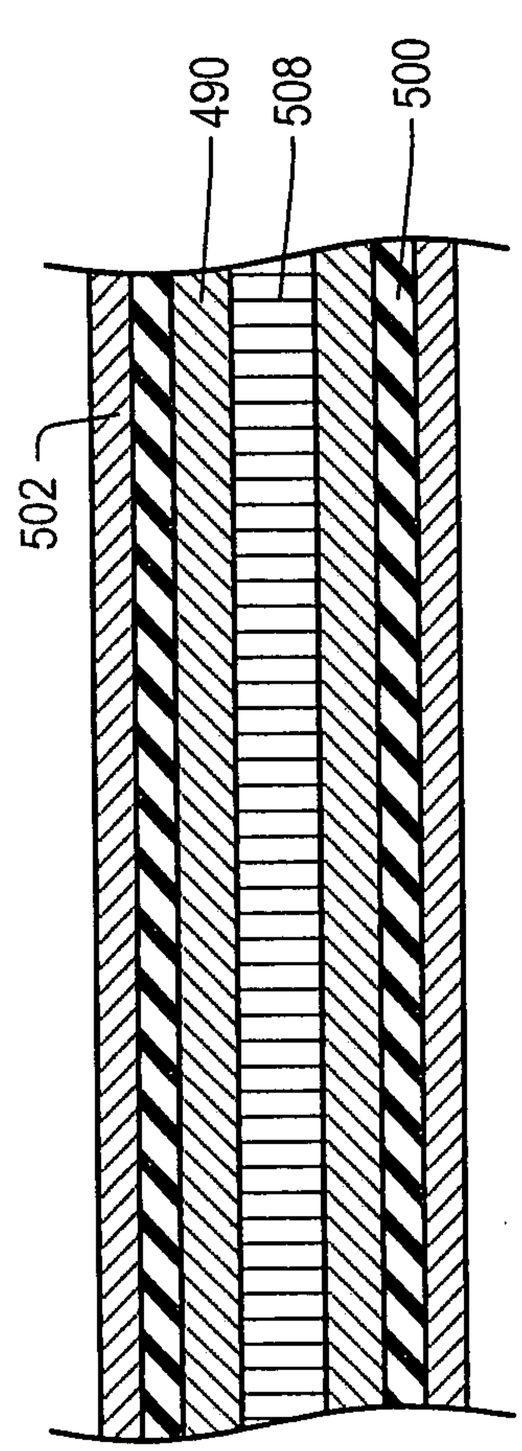


FIG. 27A

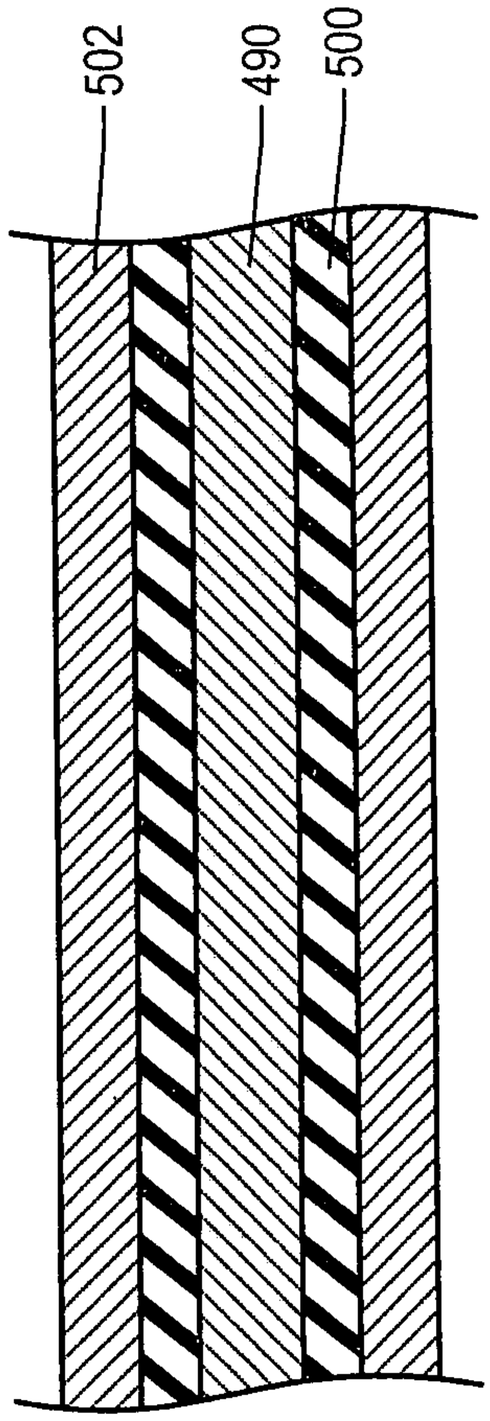


FIG. 28A

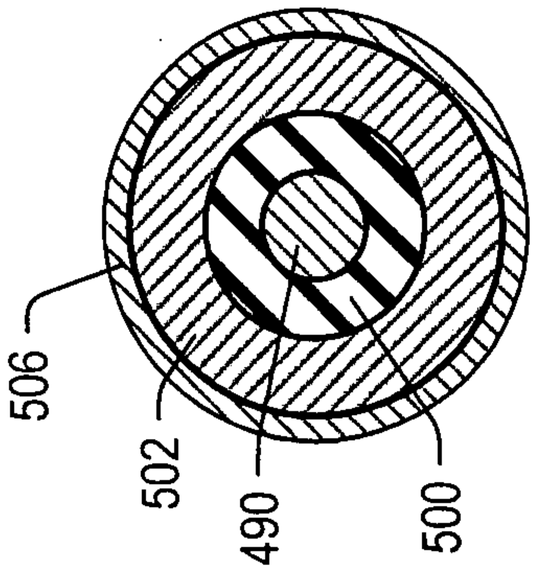


FIG. 29B

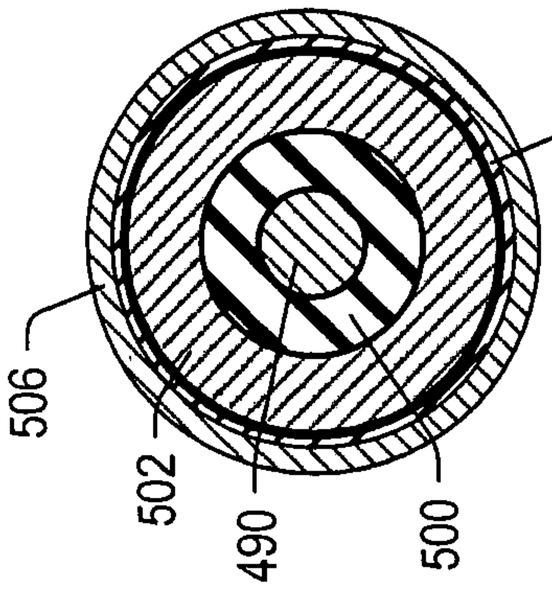


FIG. 30B

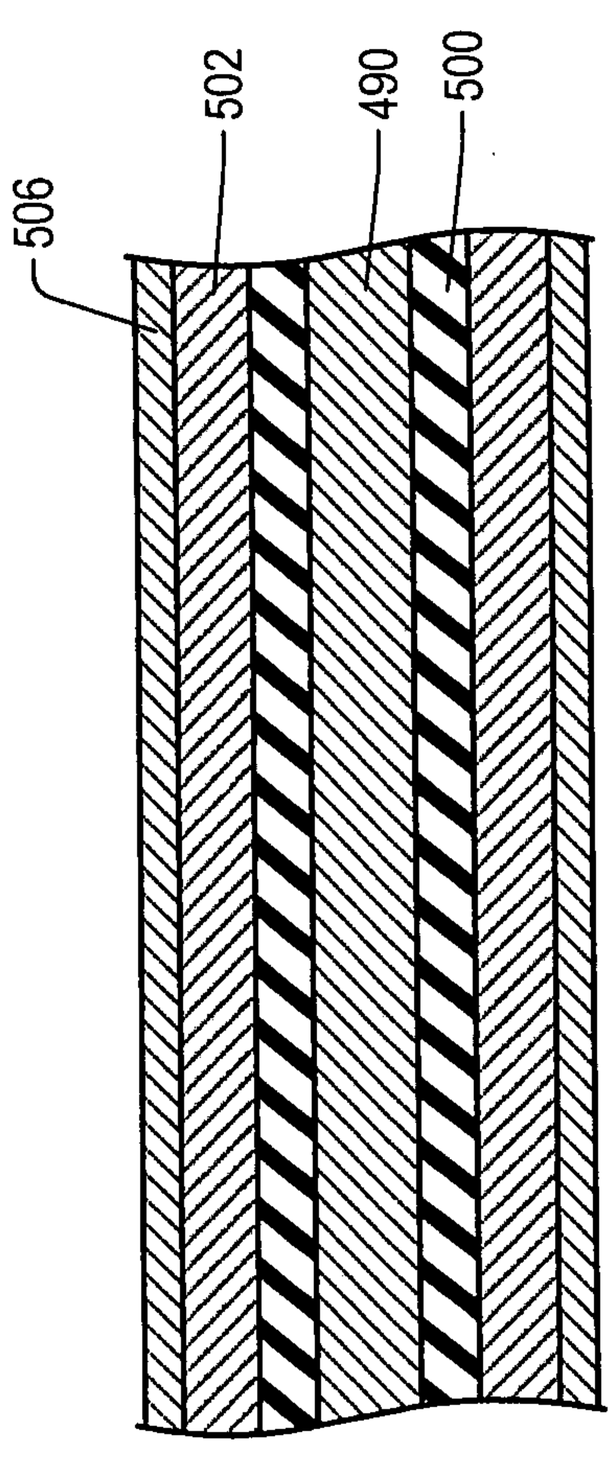


FIG. 29A

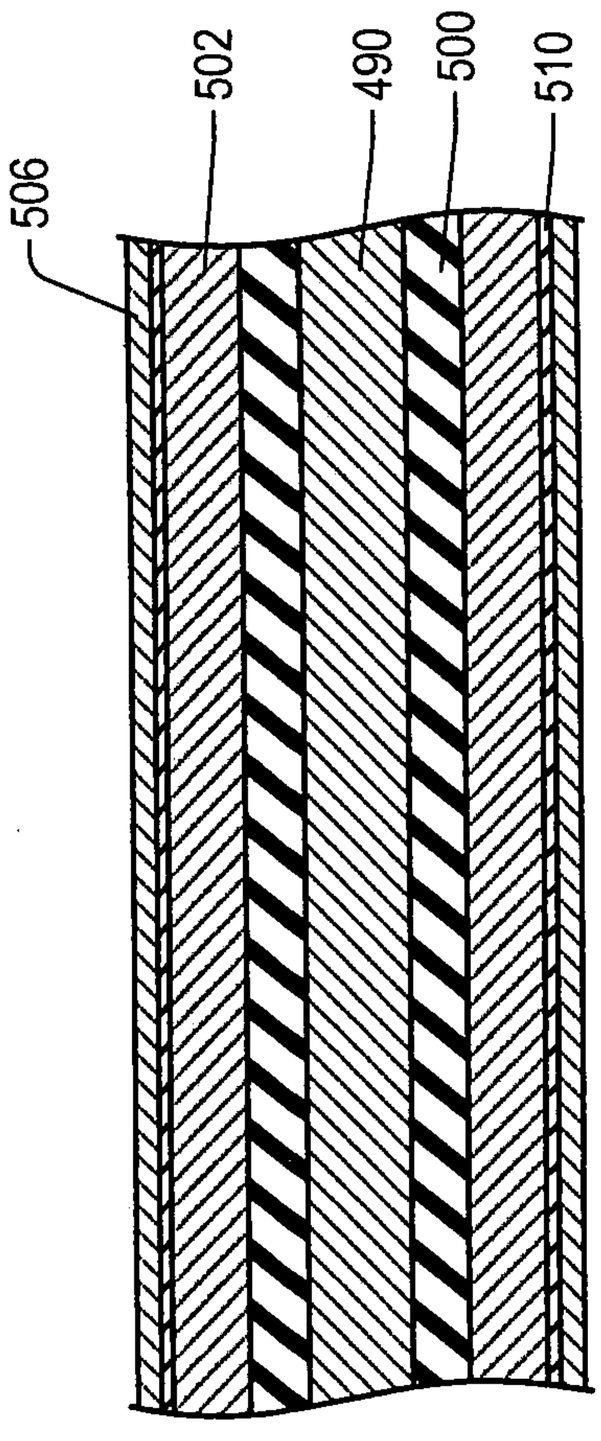


FIG. 30A

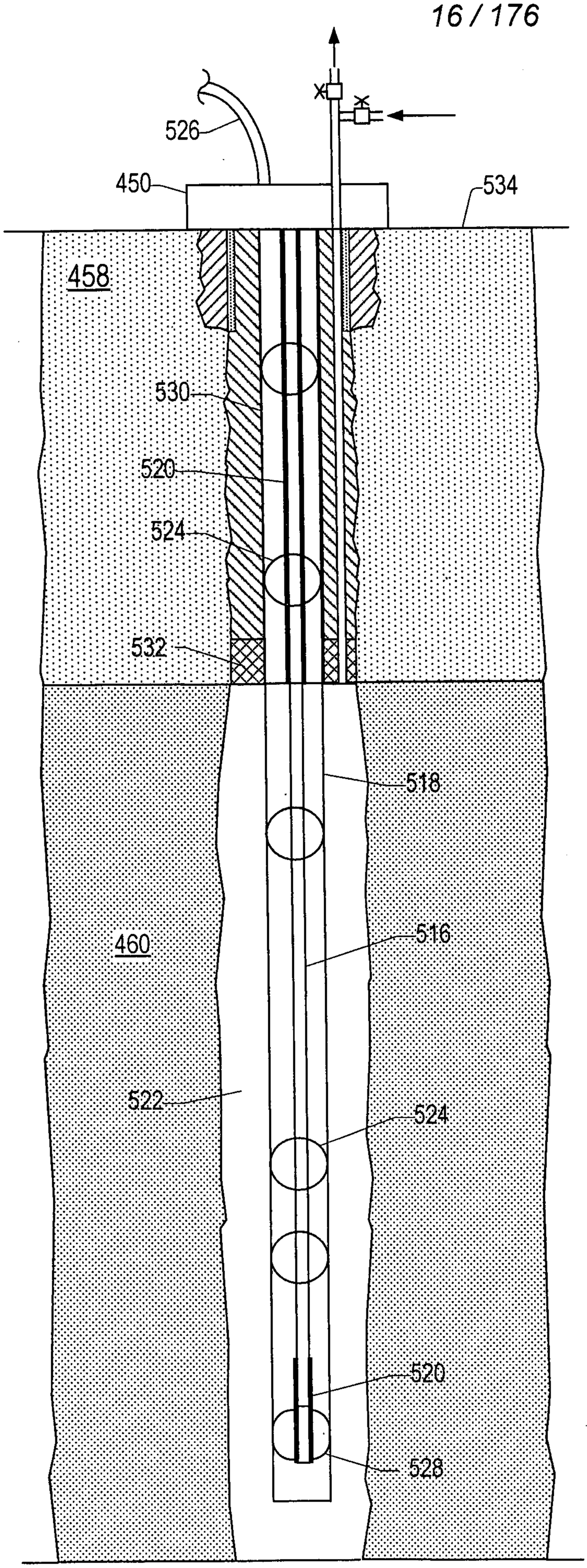


FIG. 35

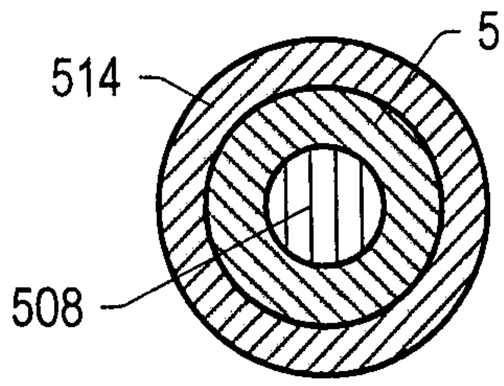


FIG. 31

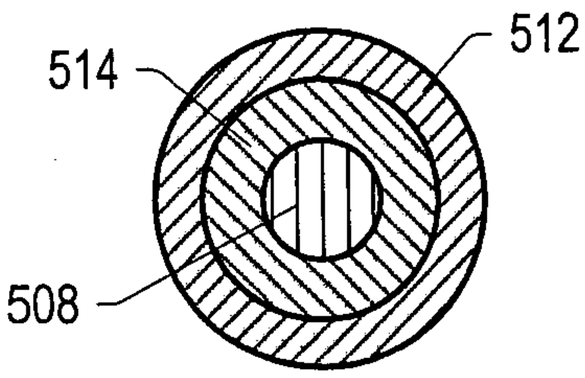


FIG. 32

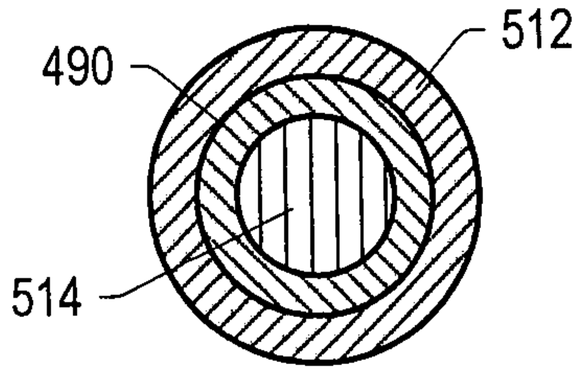


FIG. 33

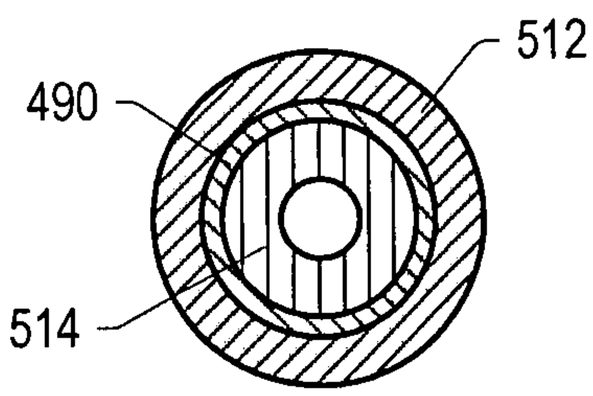


FIG. 34

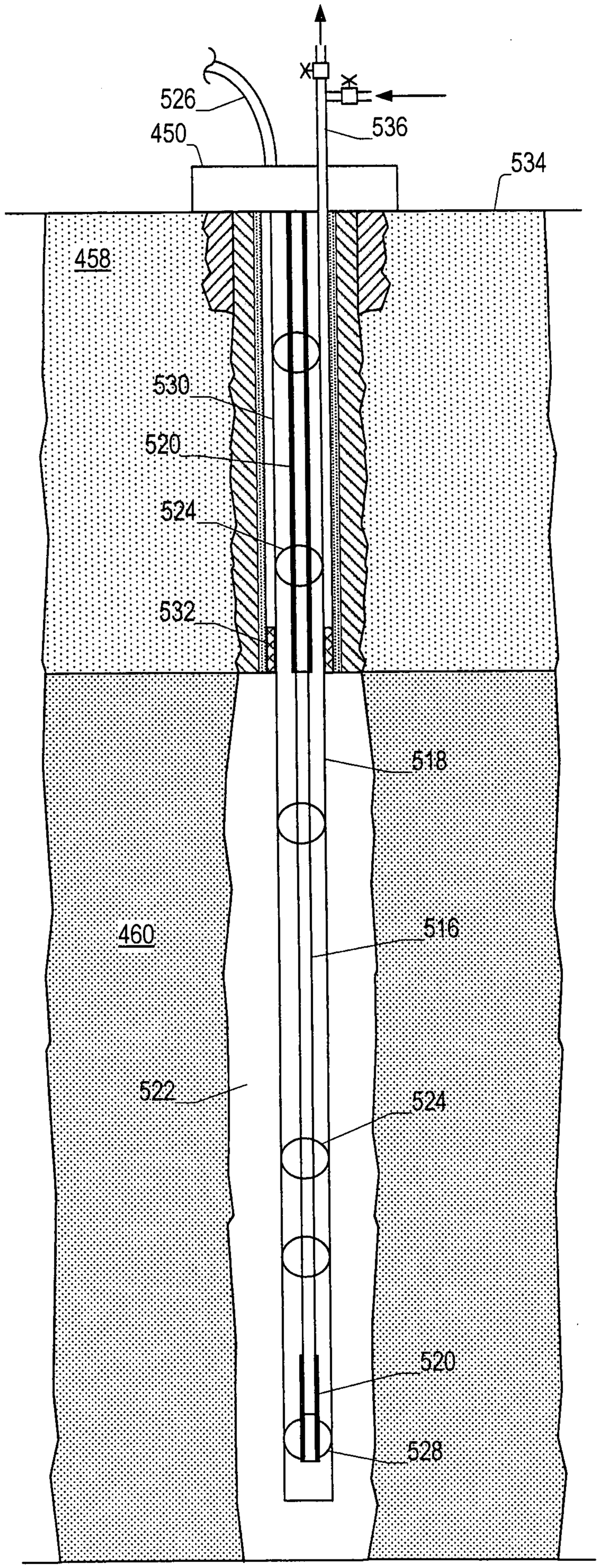


FIG. 36

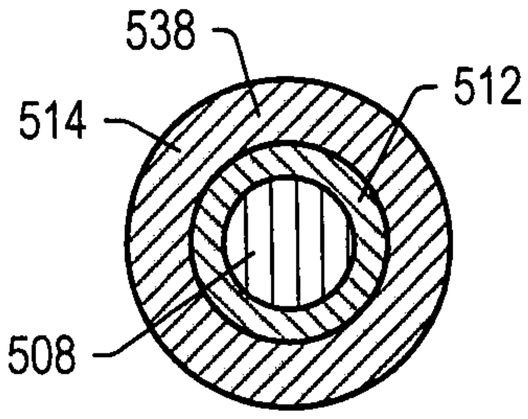


FIG. 37

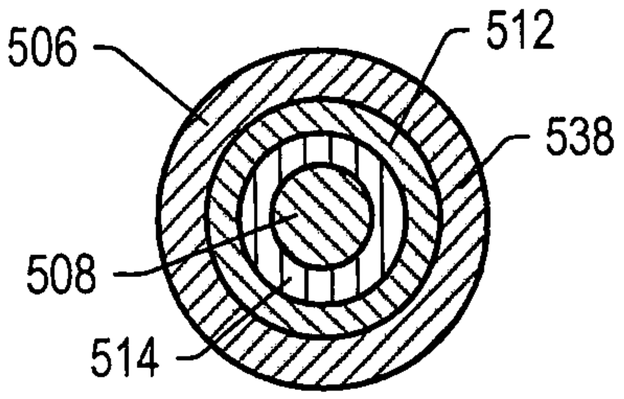


FIG. 38

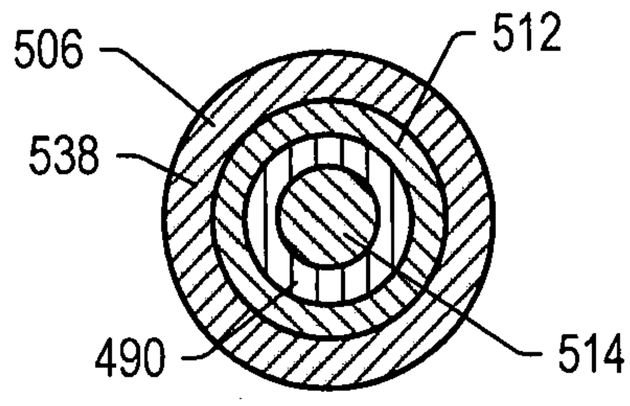


FIG. 39

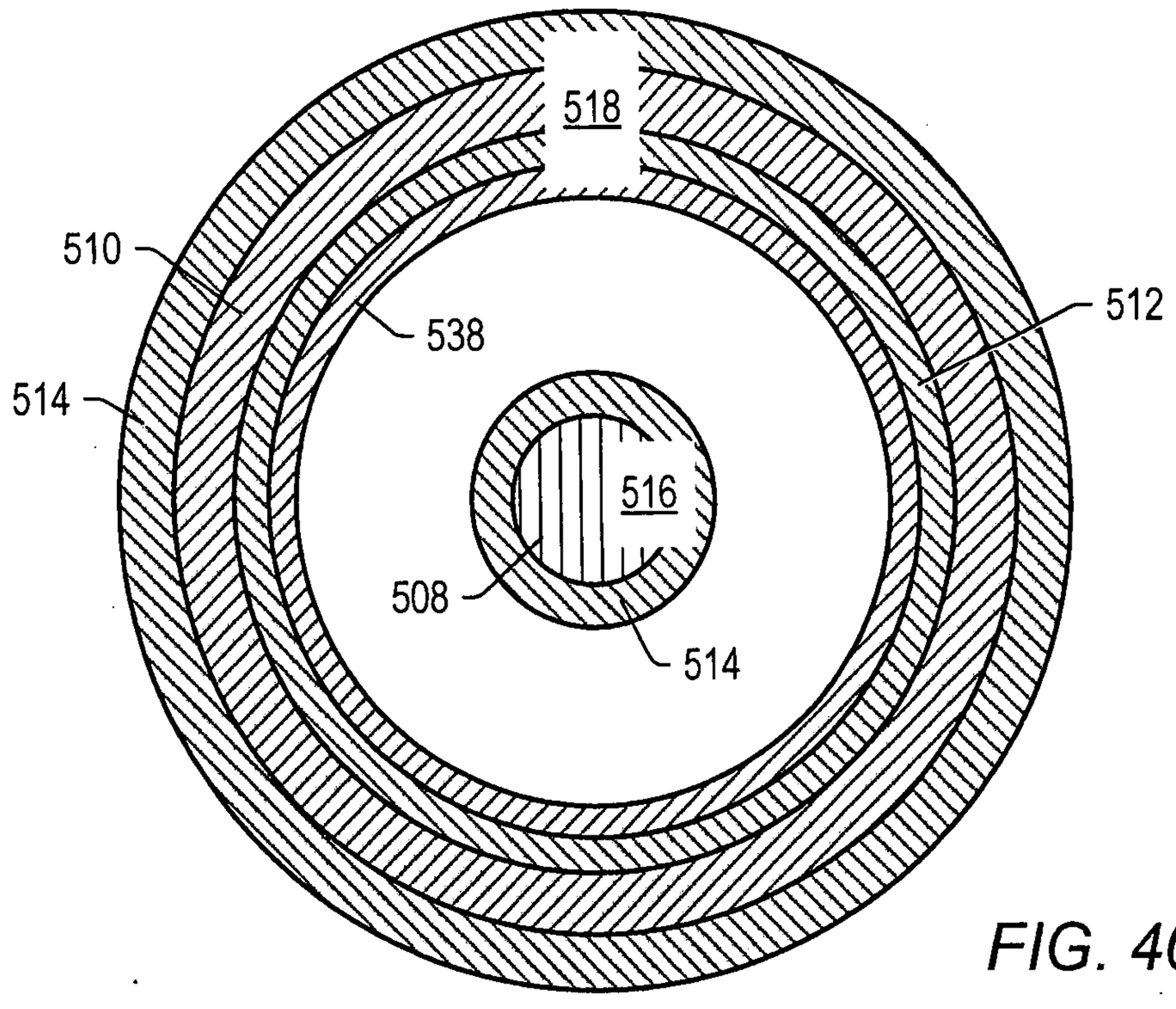


FIG. 40

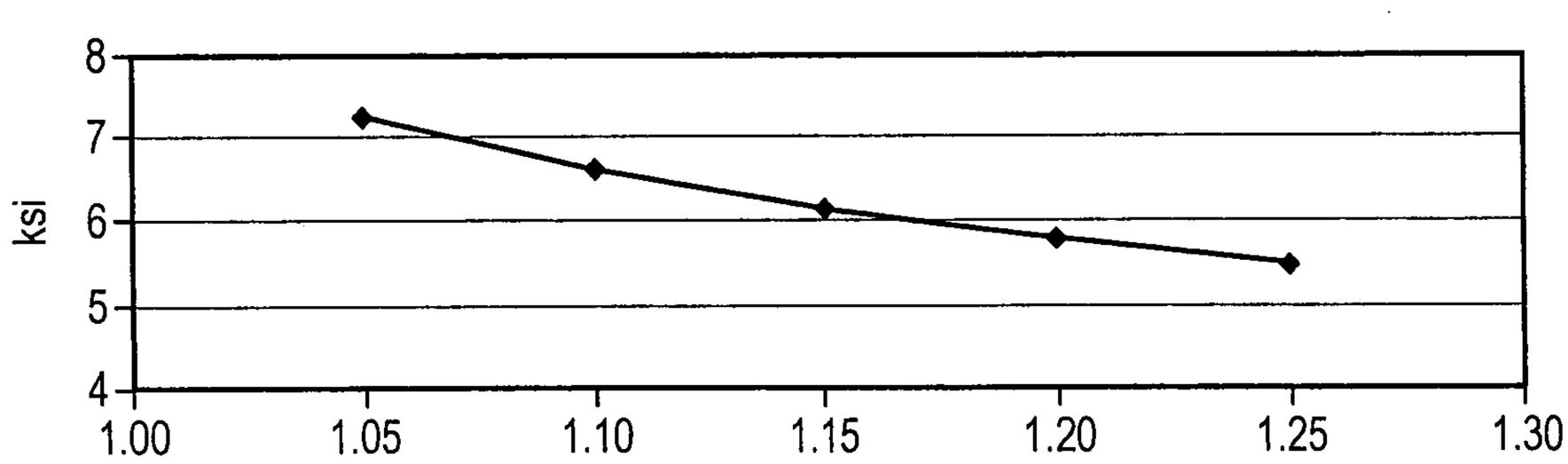


FIG. 41

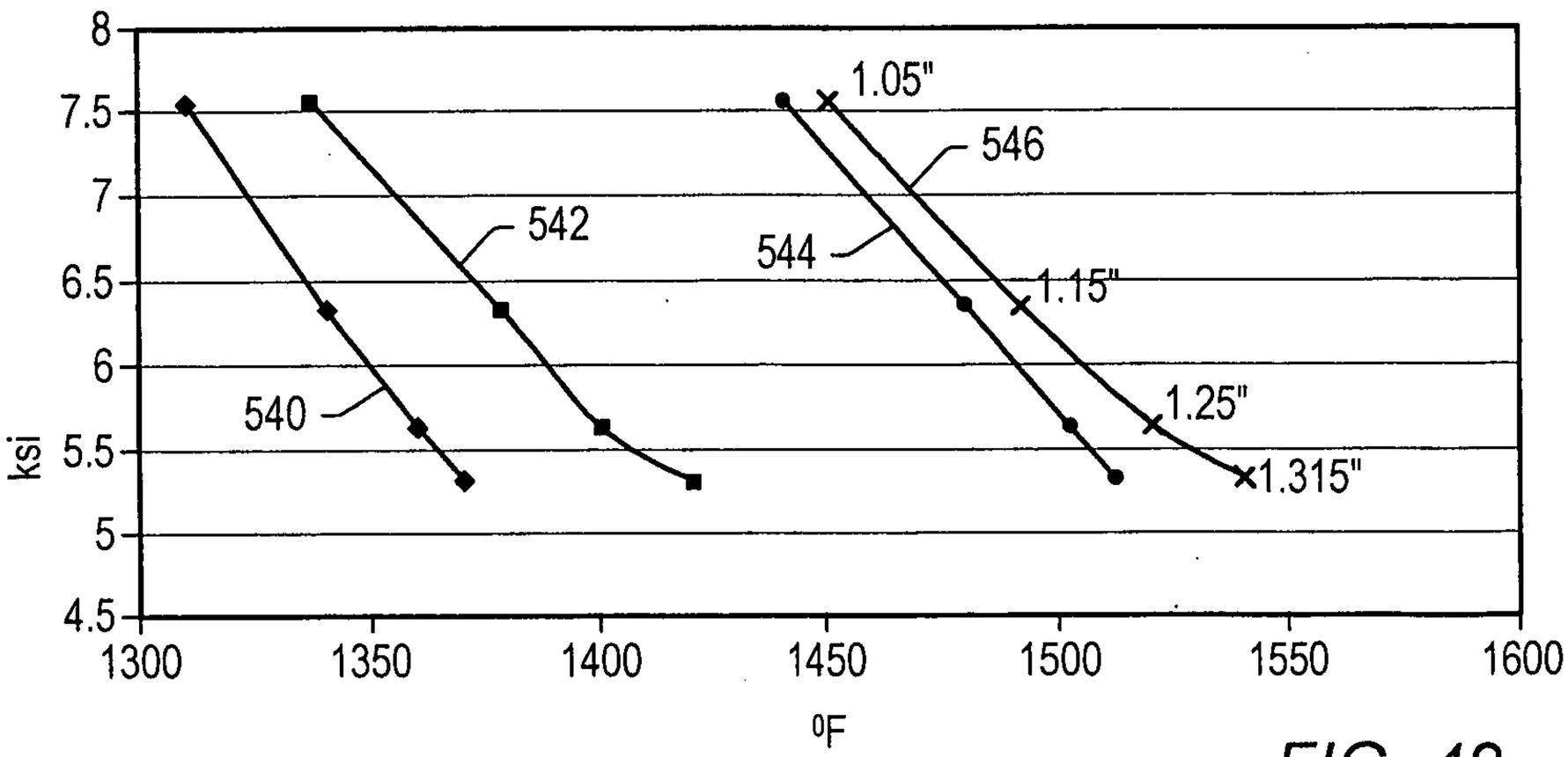


FIG. 42

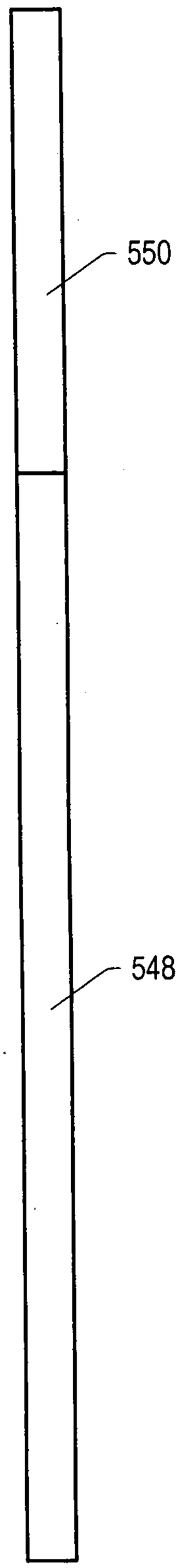


FIG. 43

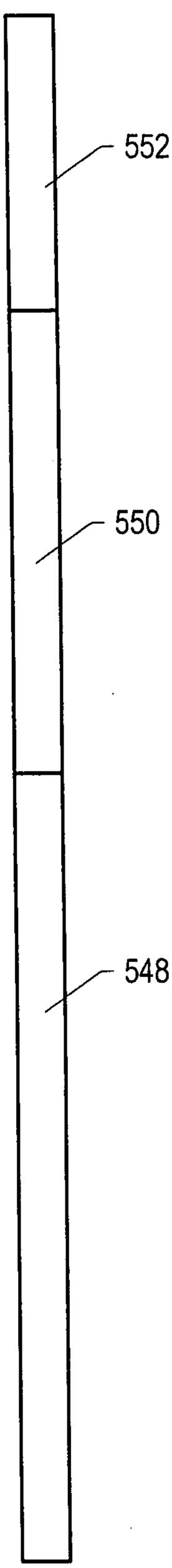


FIG. 44

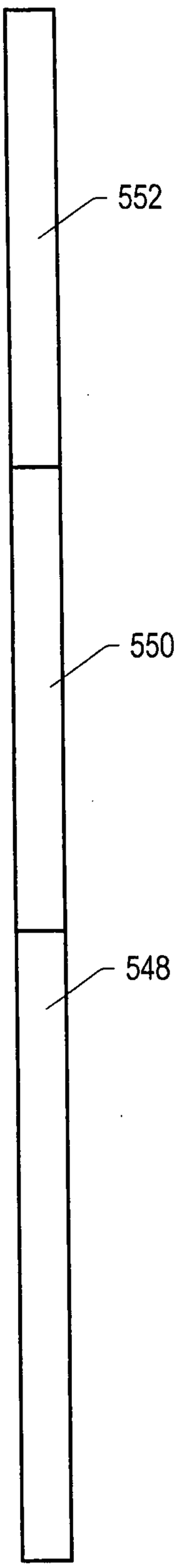


FIG. 45

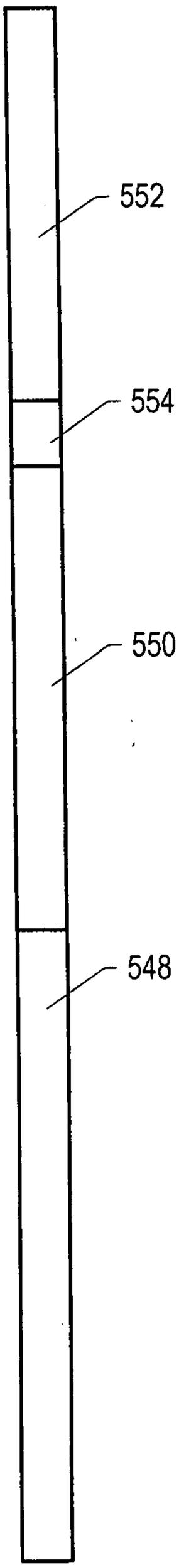


FIG. 46

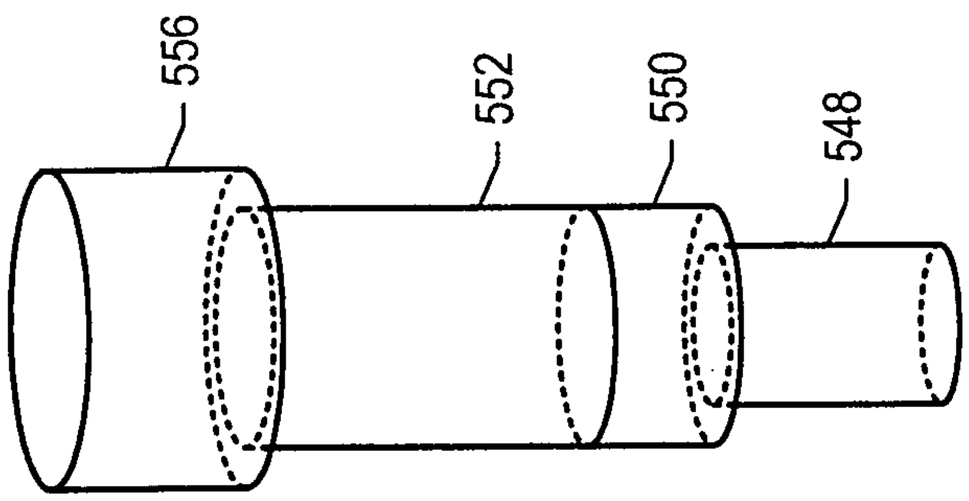


FIG. 48

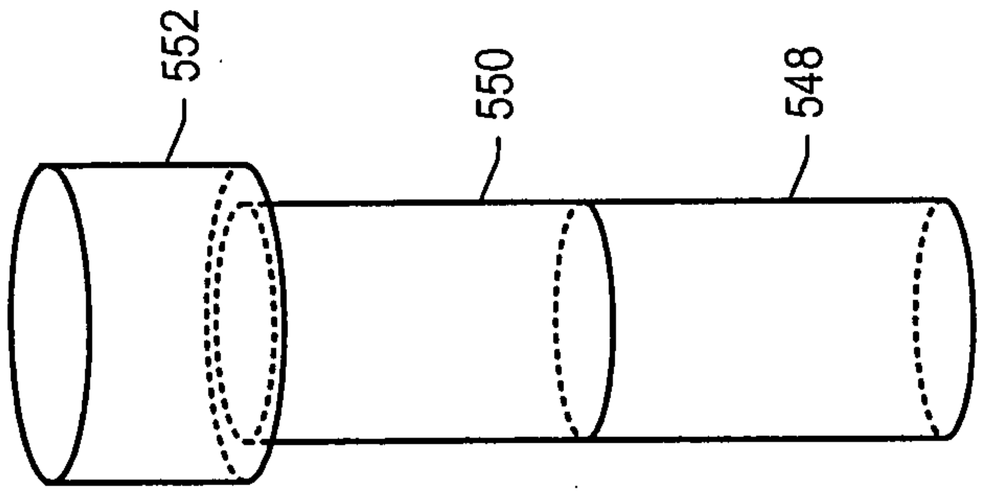


FIG. 47

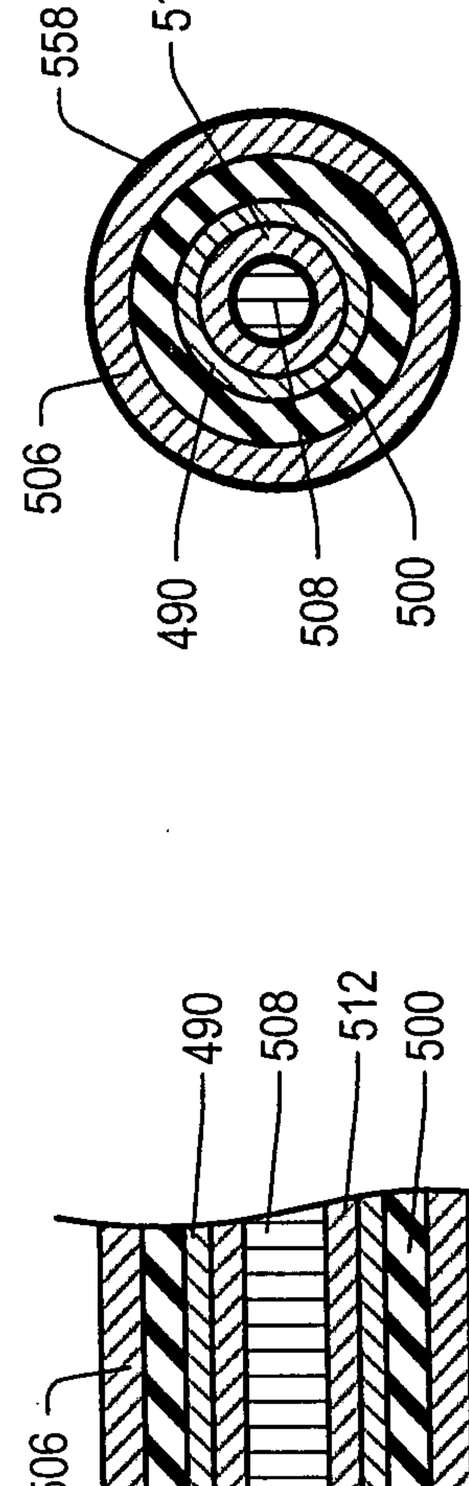


FIG. 49B

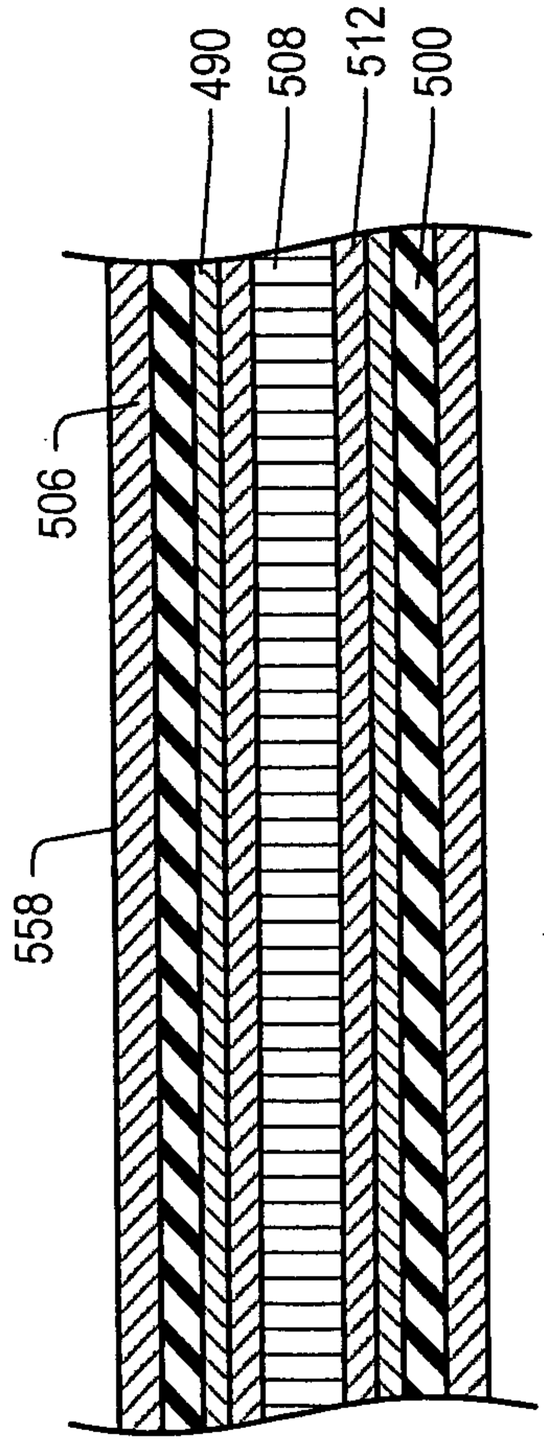


FIG. 49A

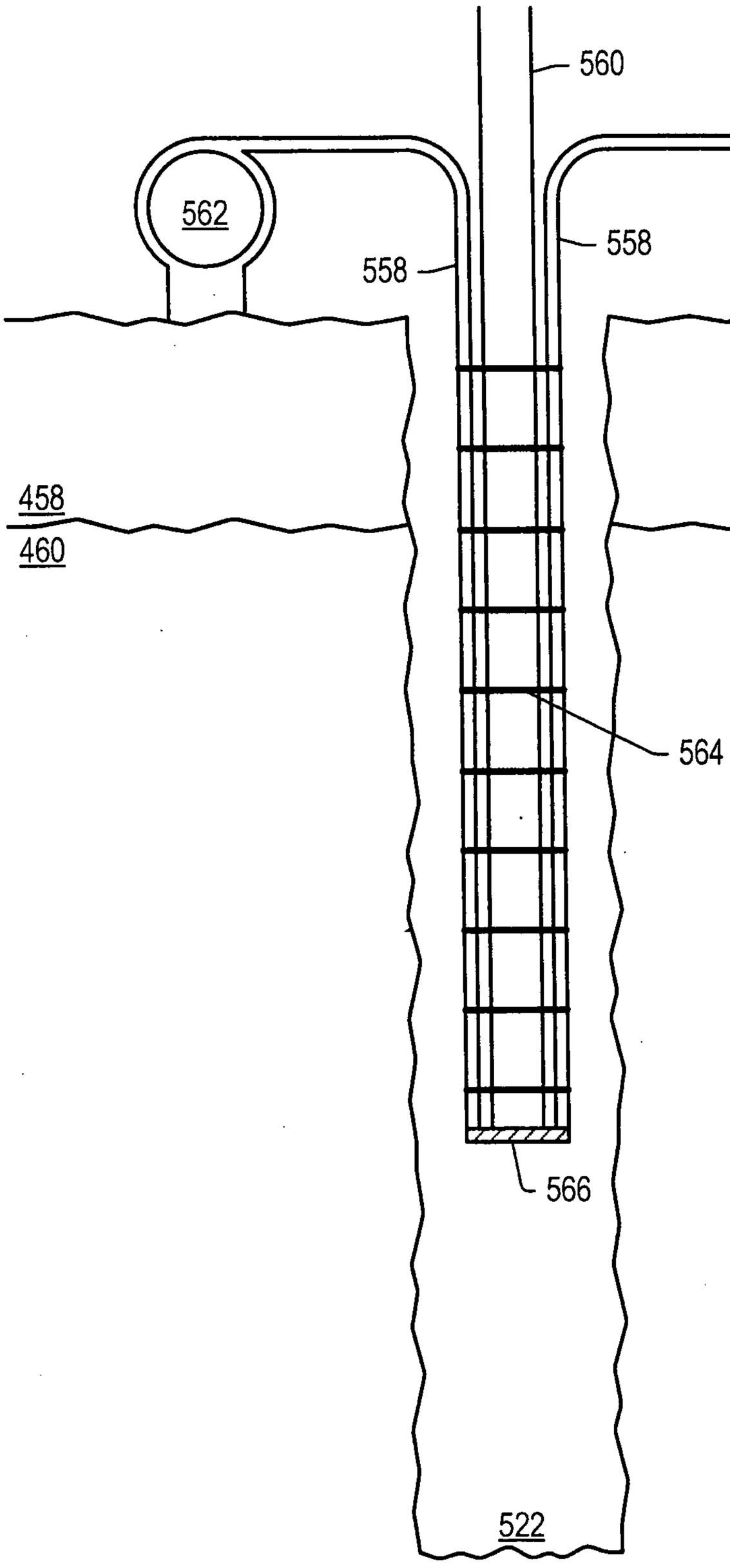


FIG. 50A

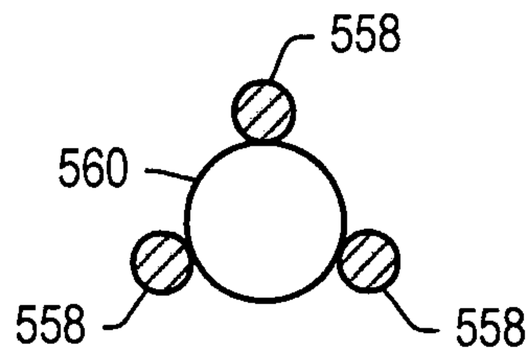


FIG. 50B

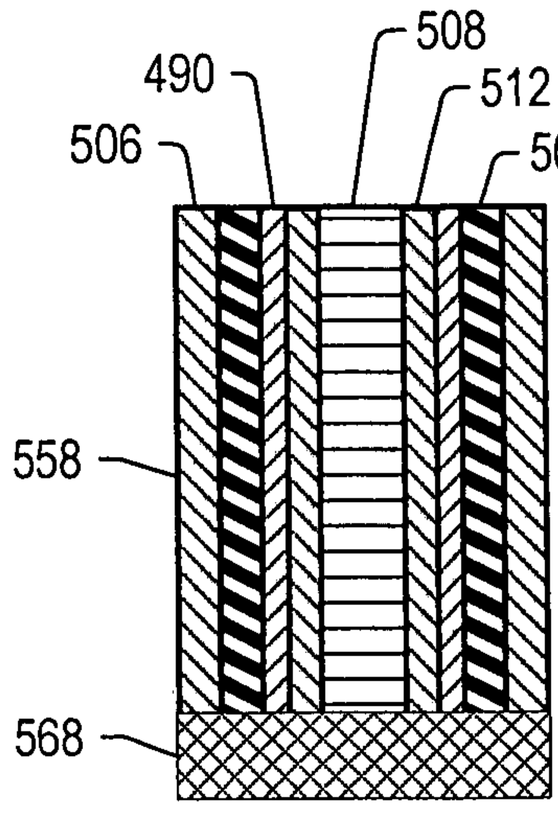


FIG. 50C

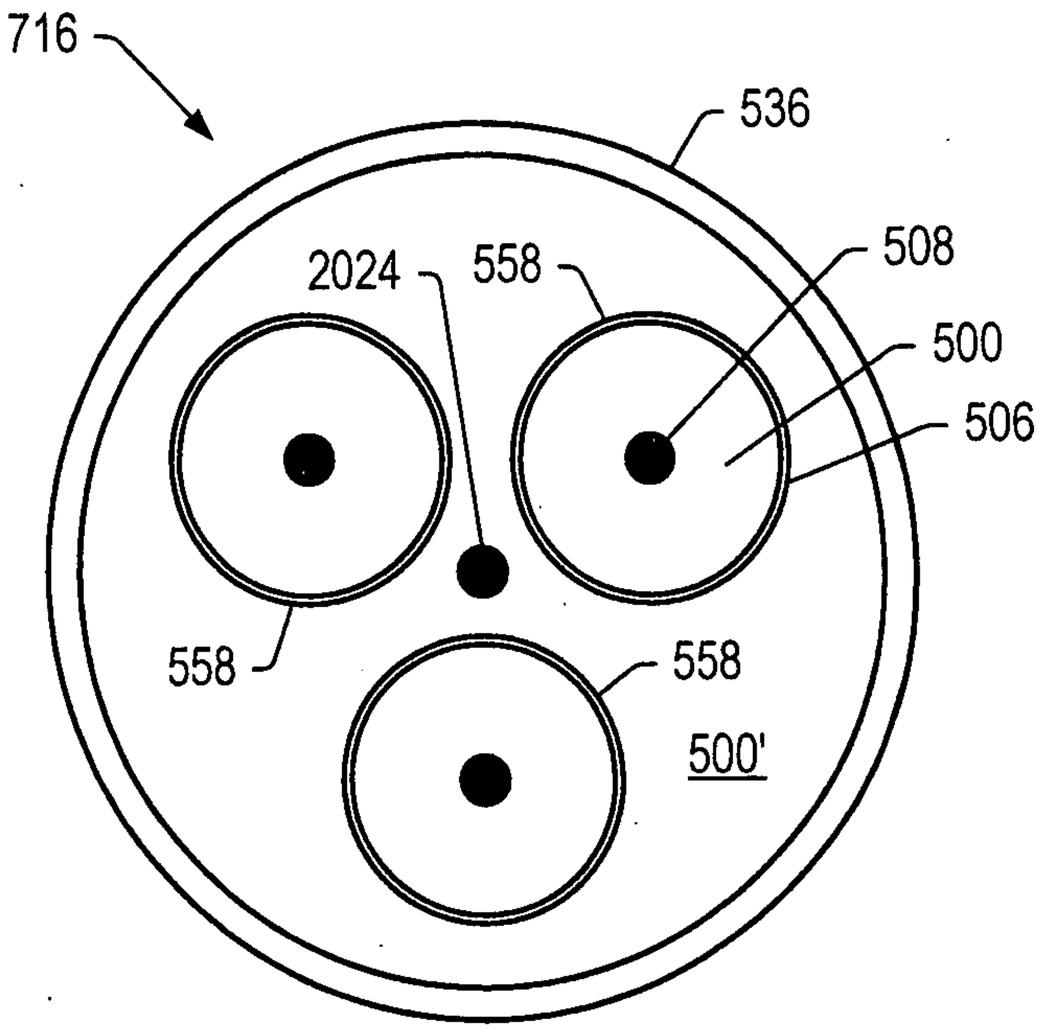


FIG. 51

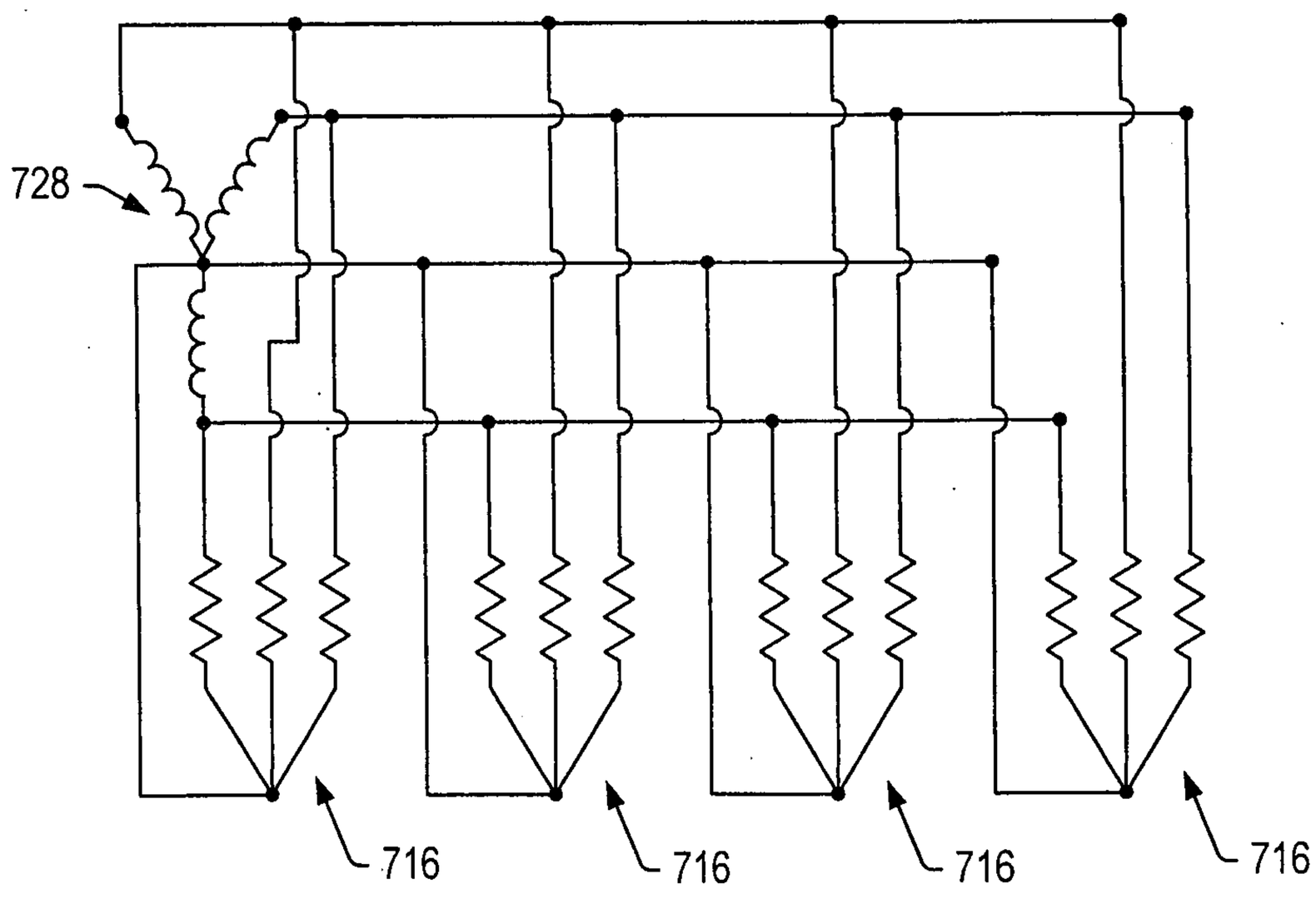


FIG. 52

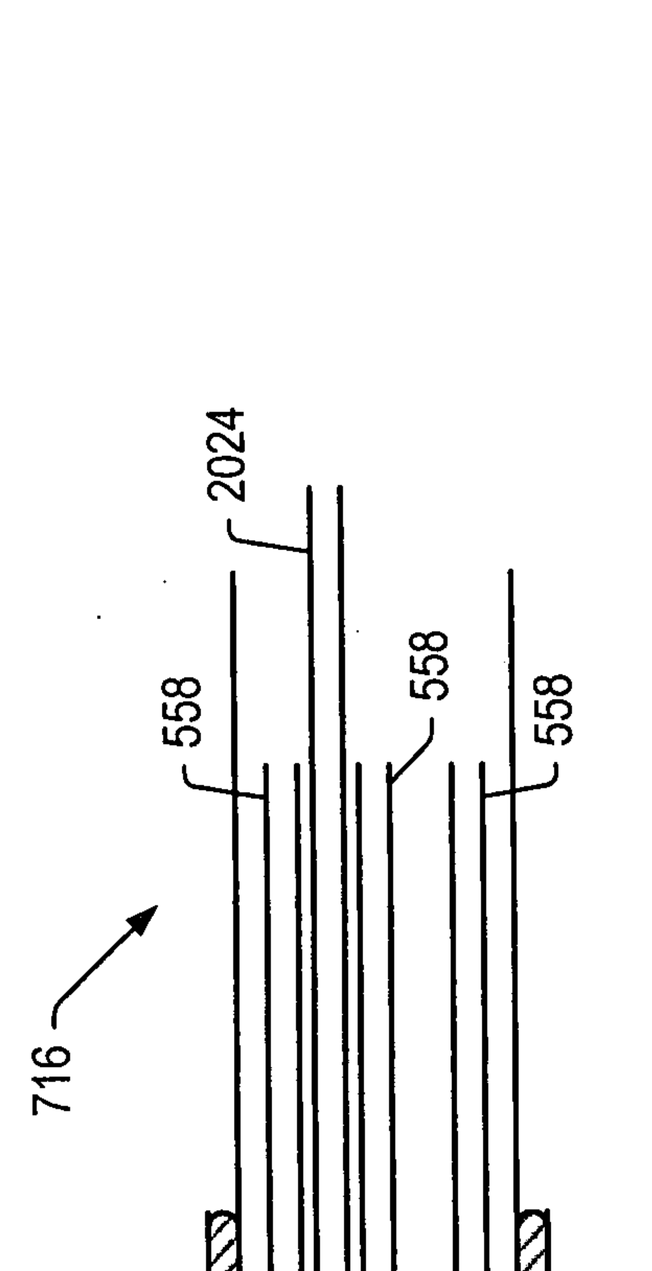


FIG. 53

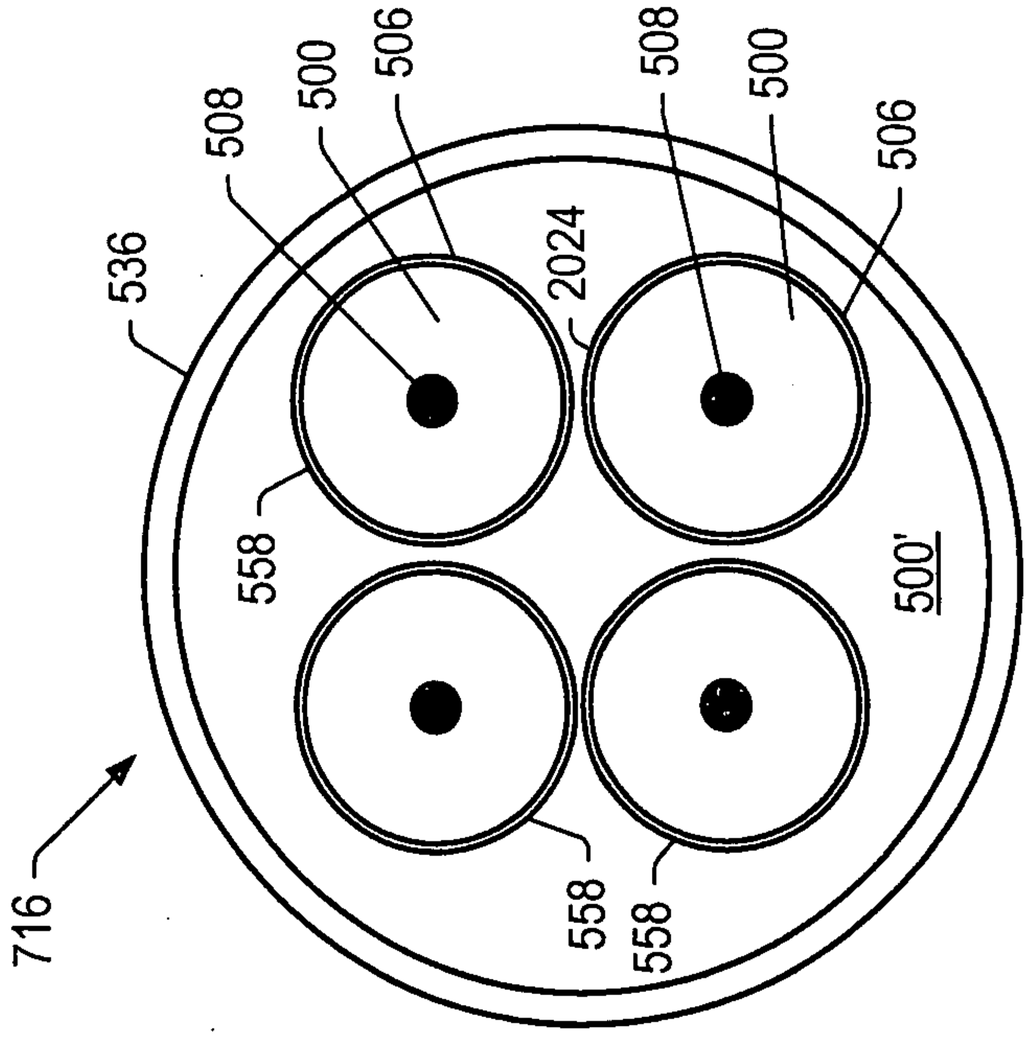


FIG. 55

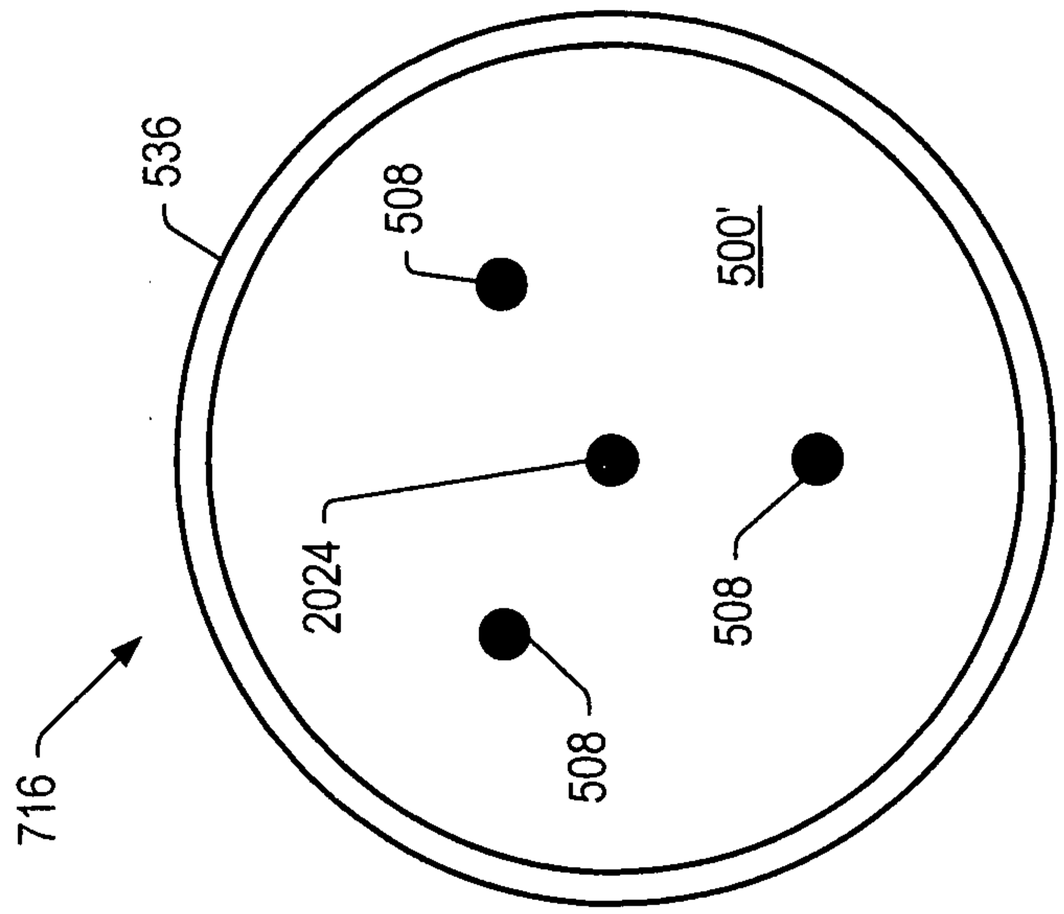


FIG. 54

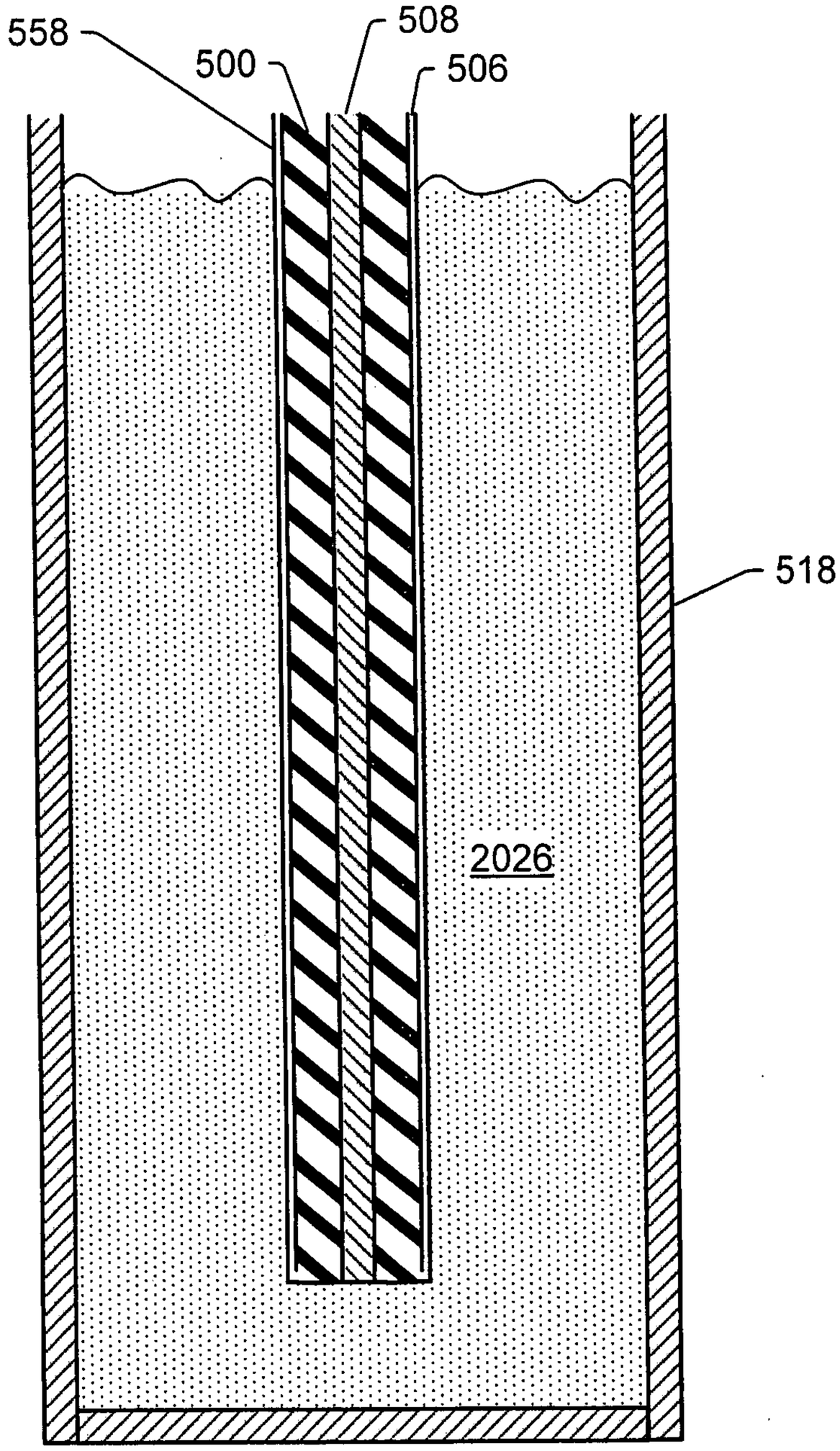


FIG. 56

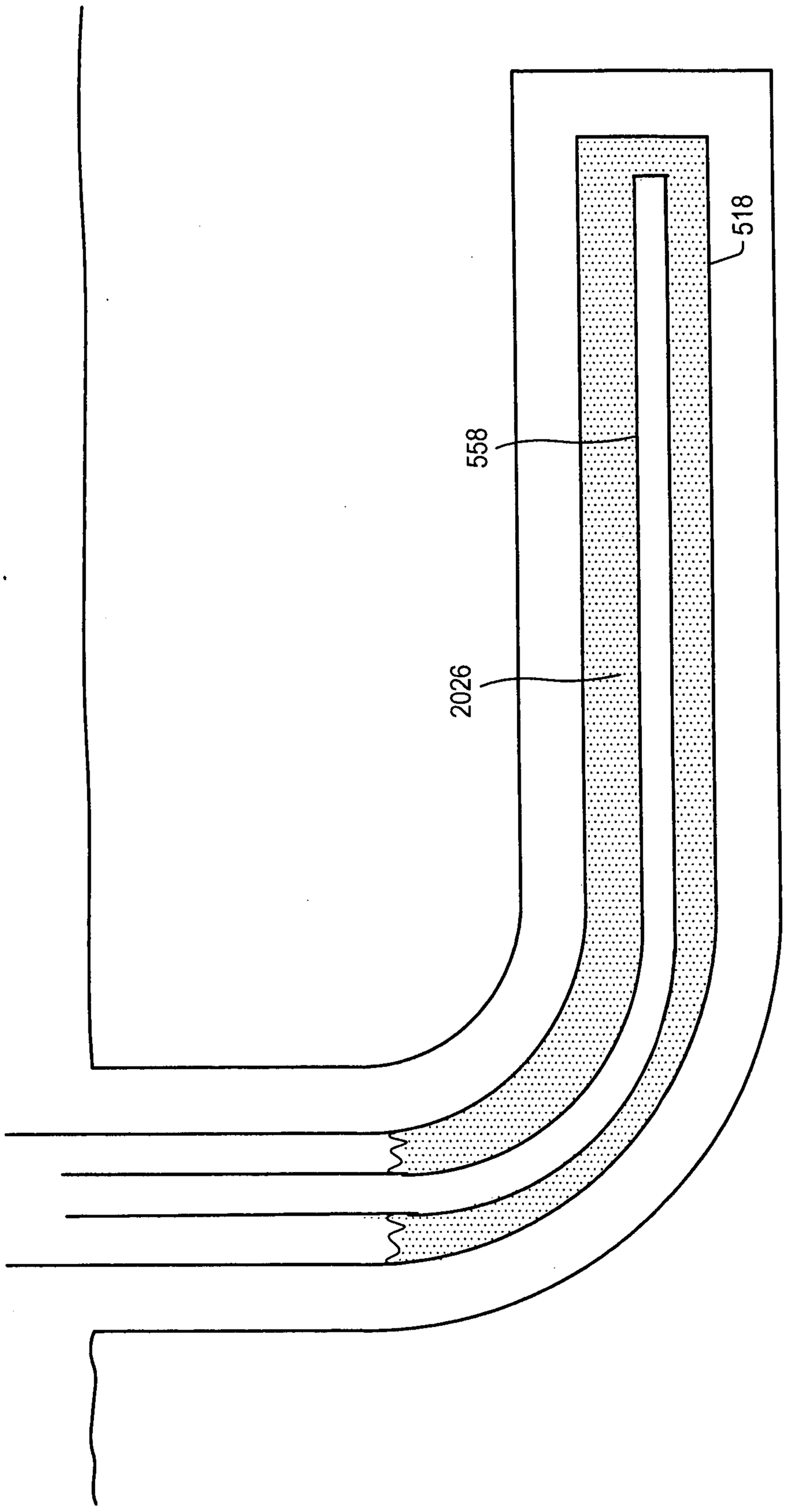


FIG. 57

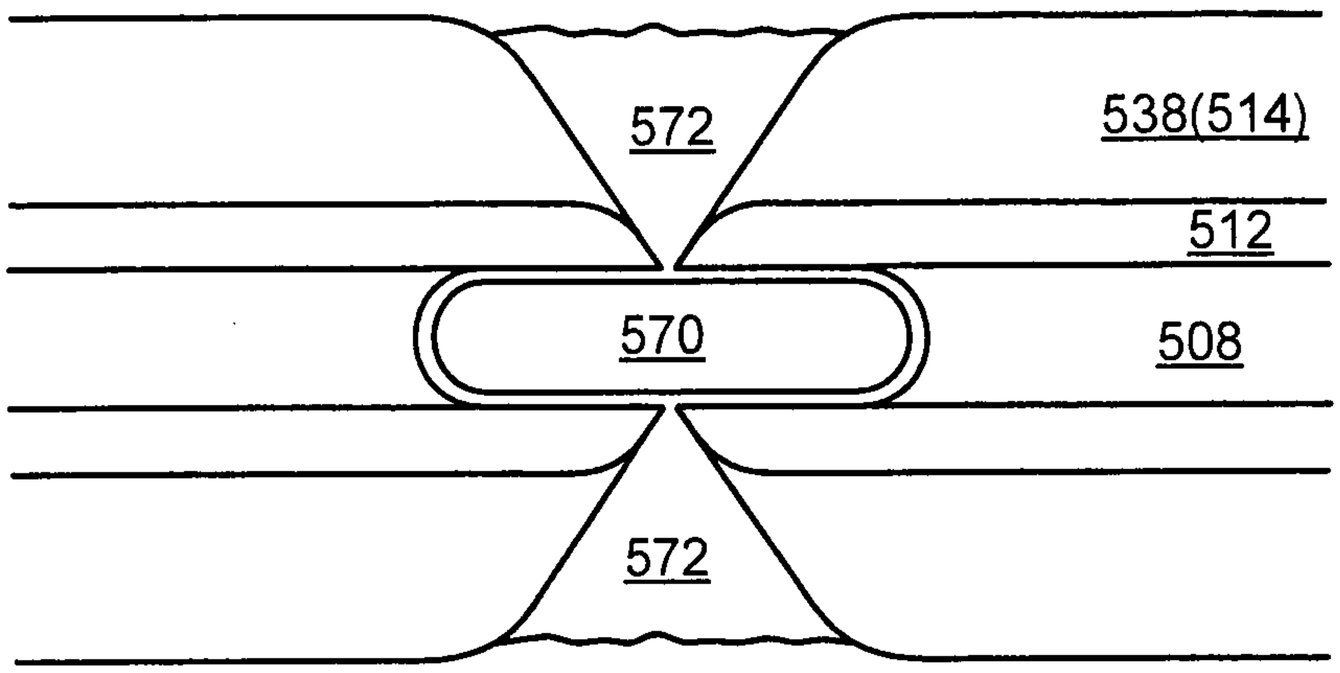


FIG. 58

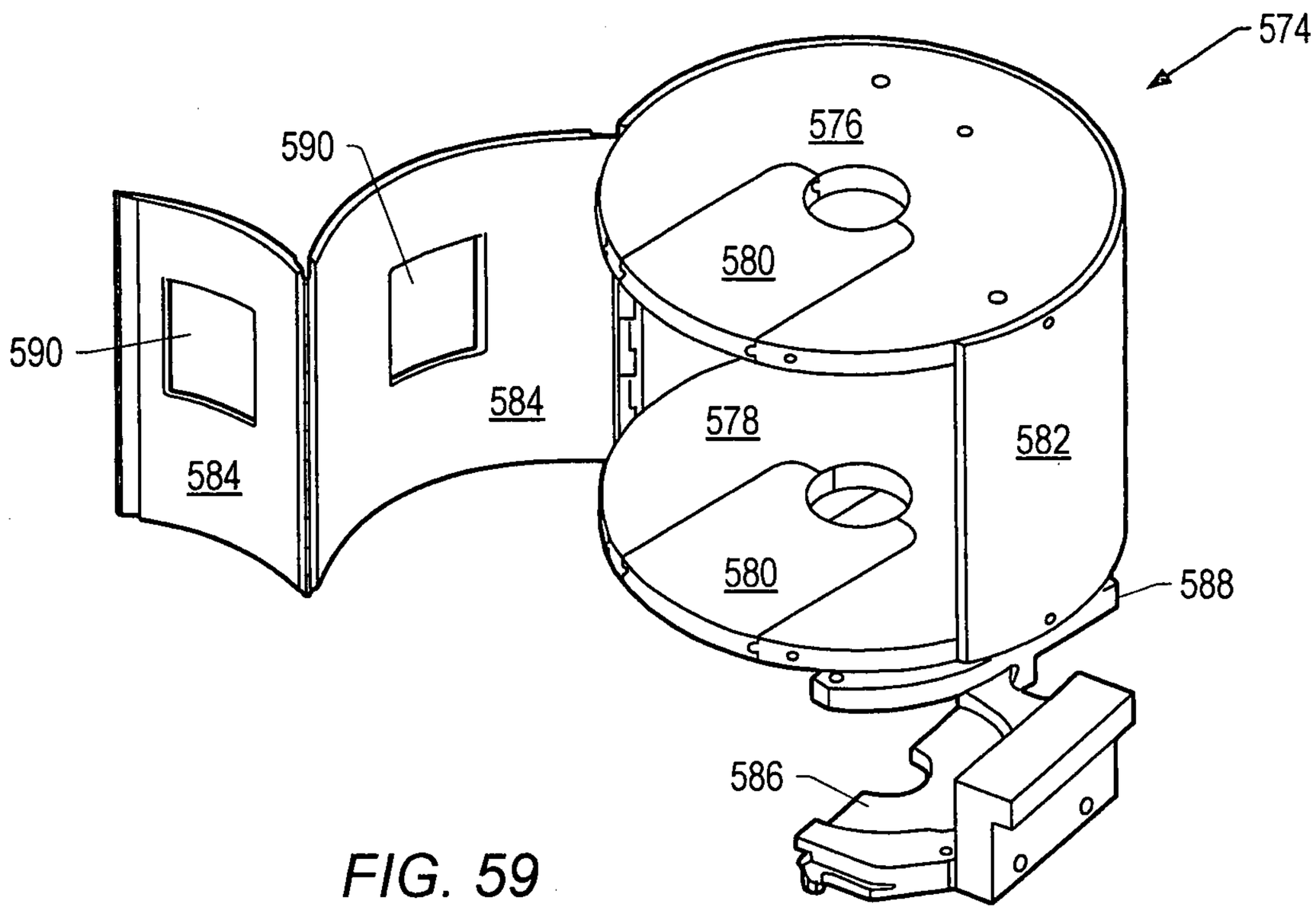


FIG. 59

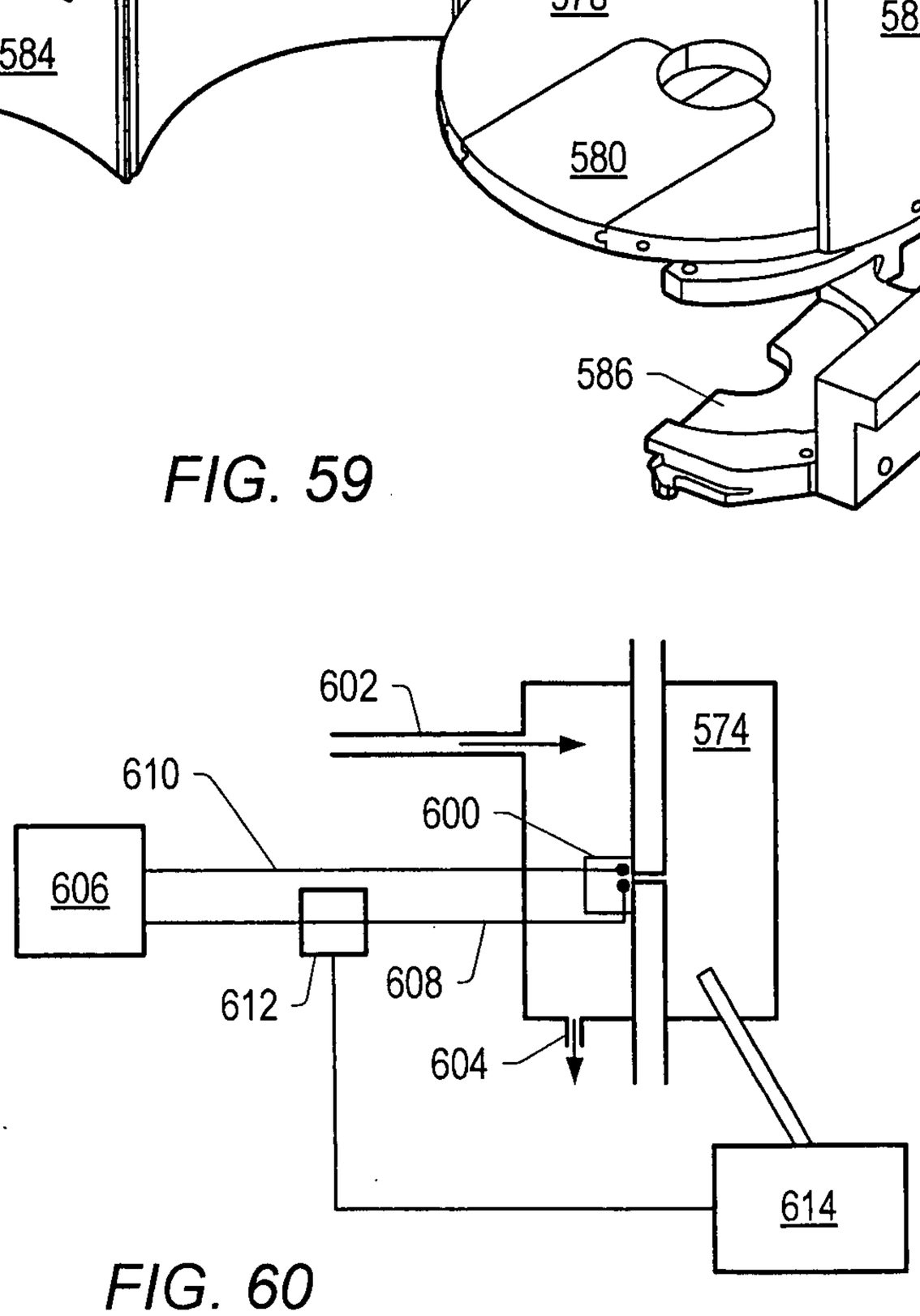


FIG. 60

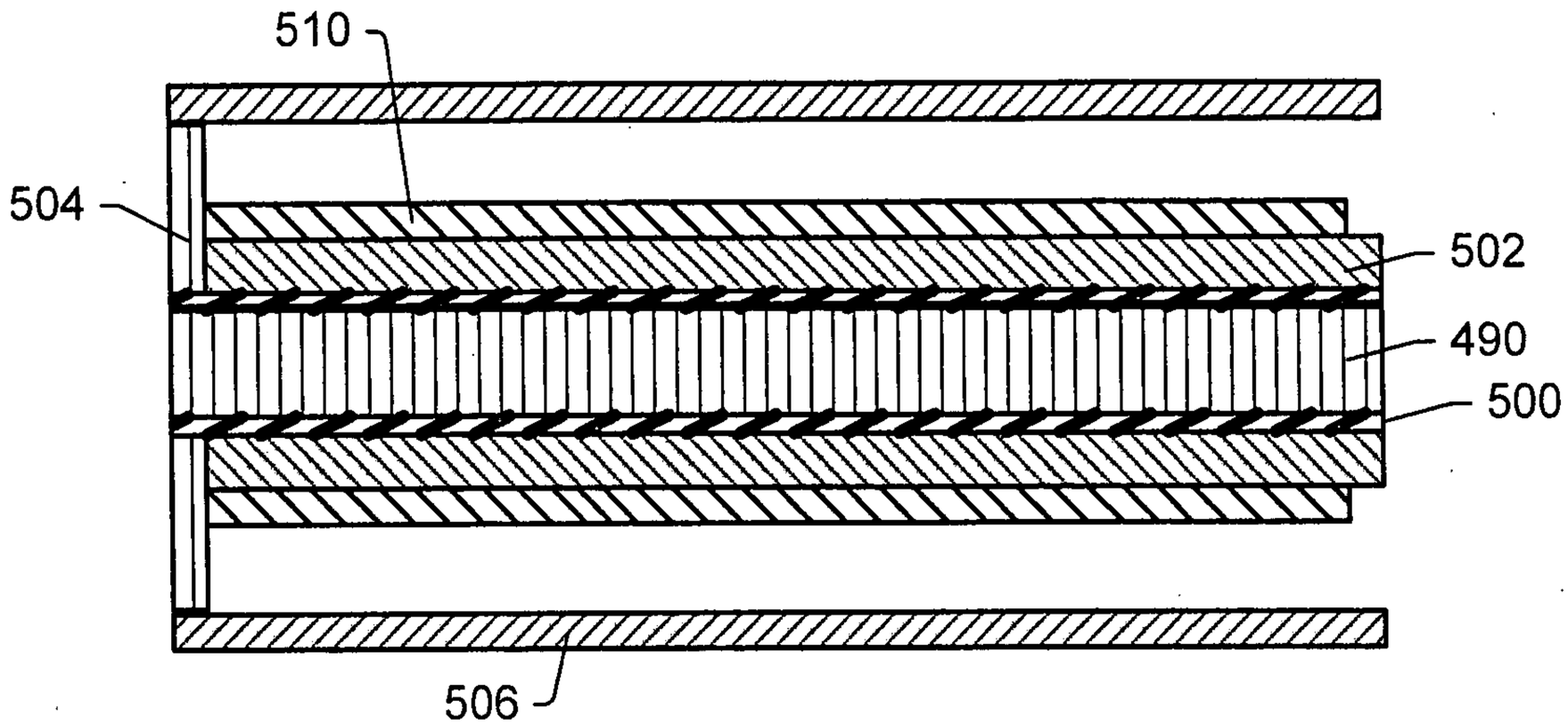


FIG. 61

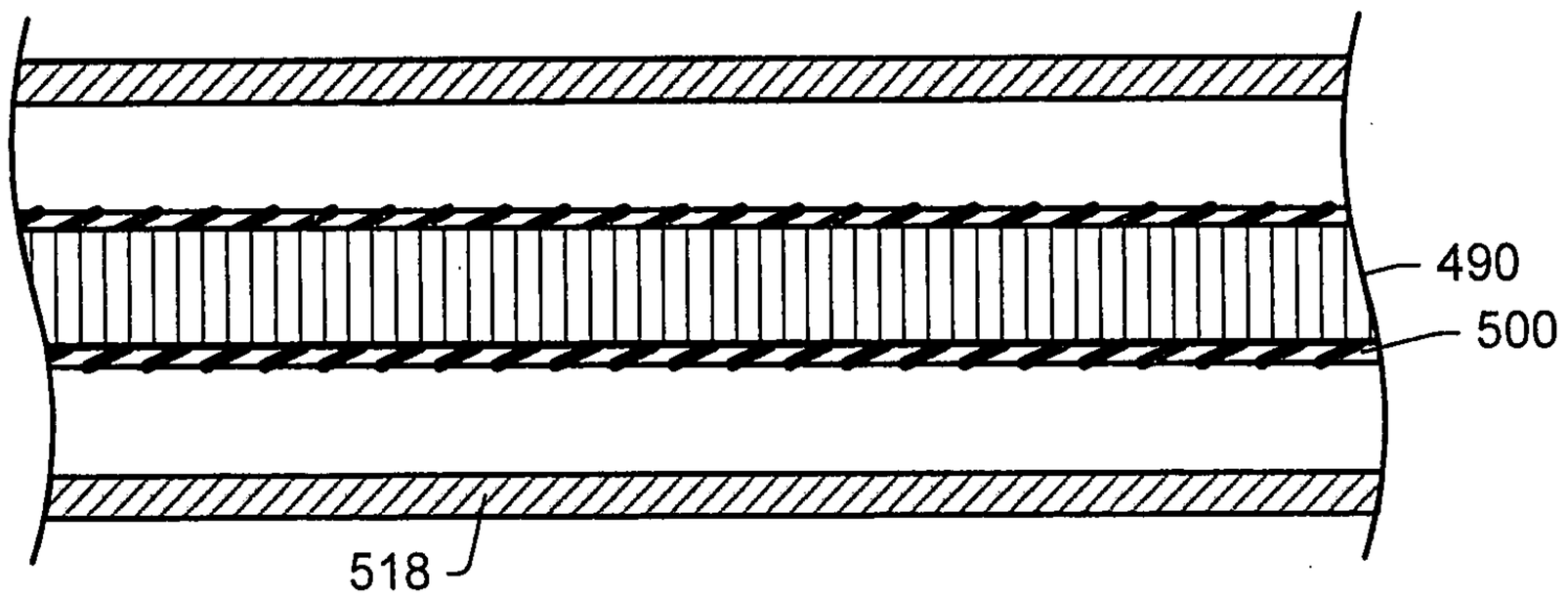


FIG. 62

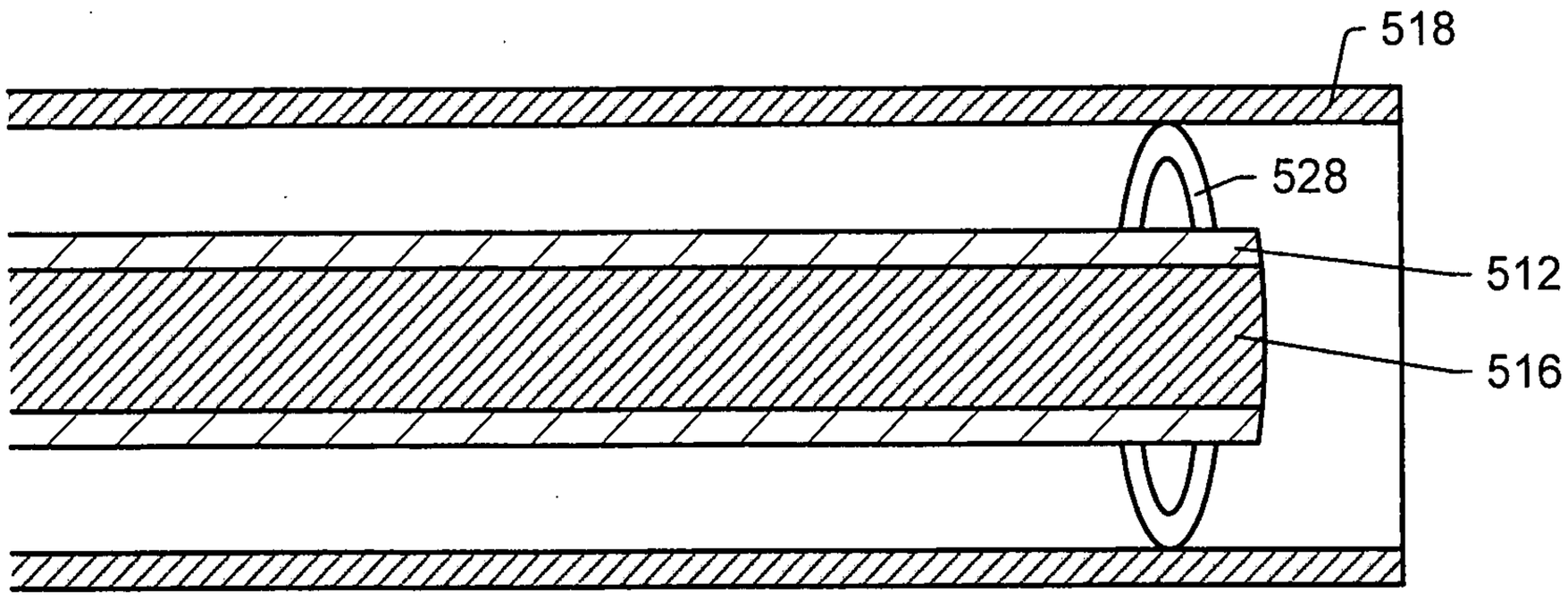


FIG. 63

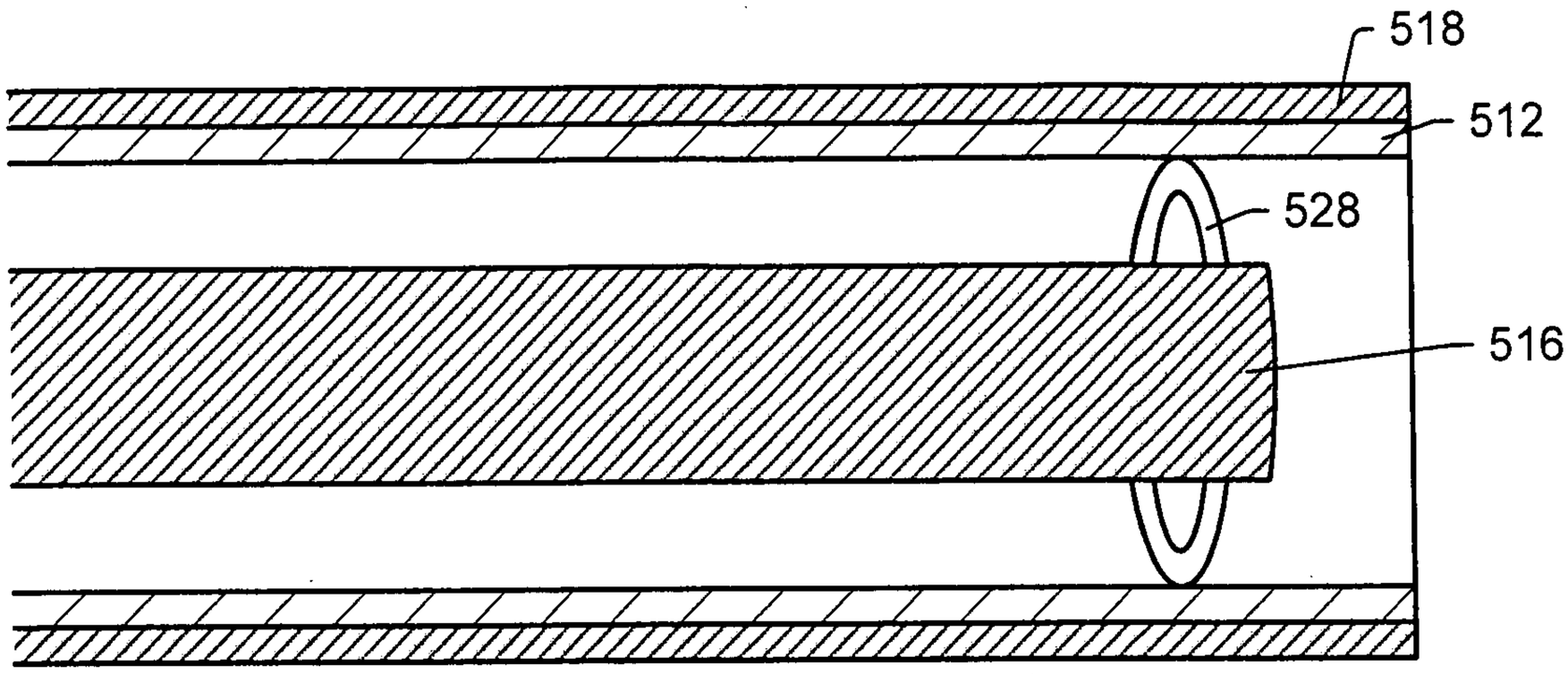


FIG. 64

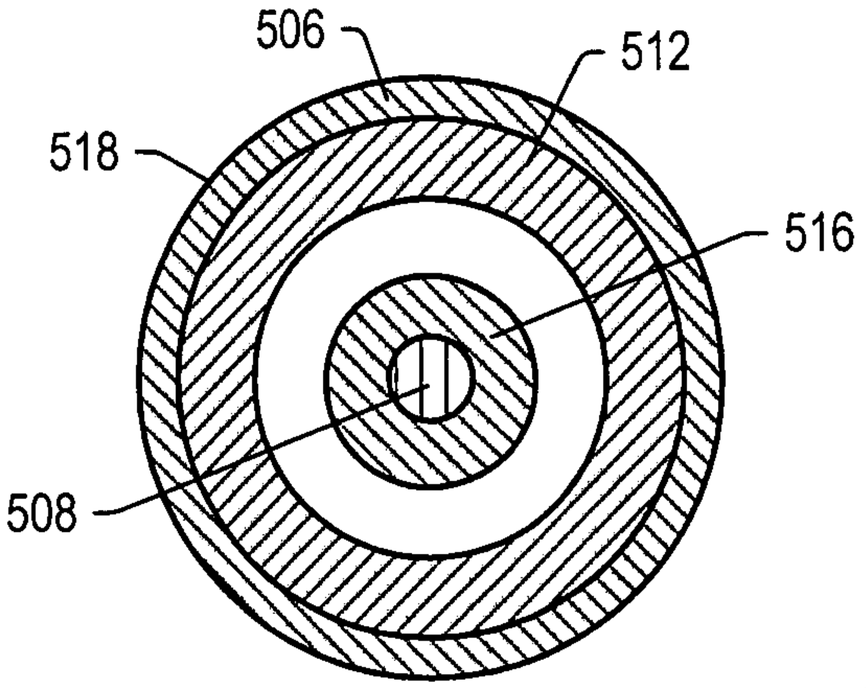


FIG. 65

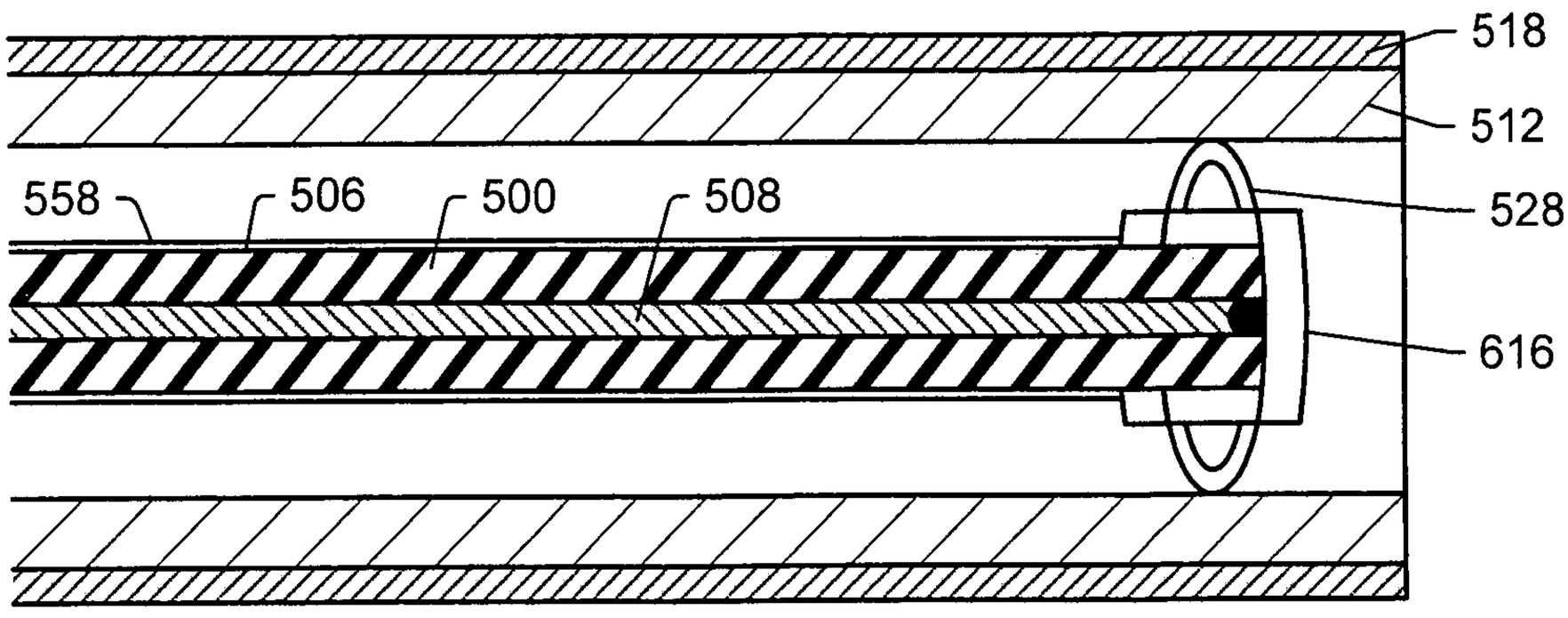


FIG. 66

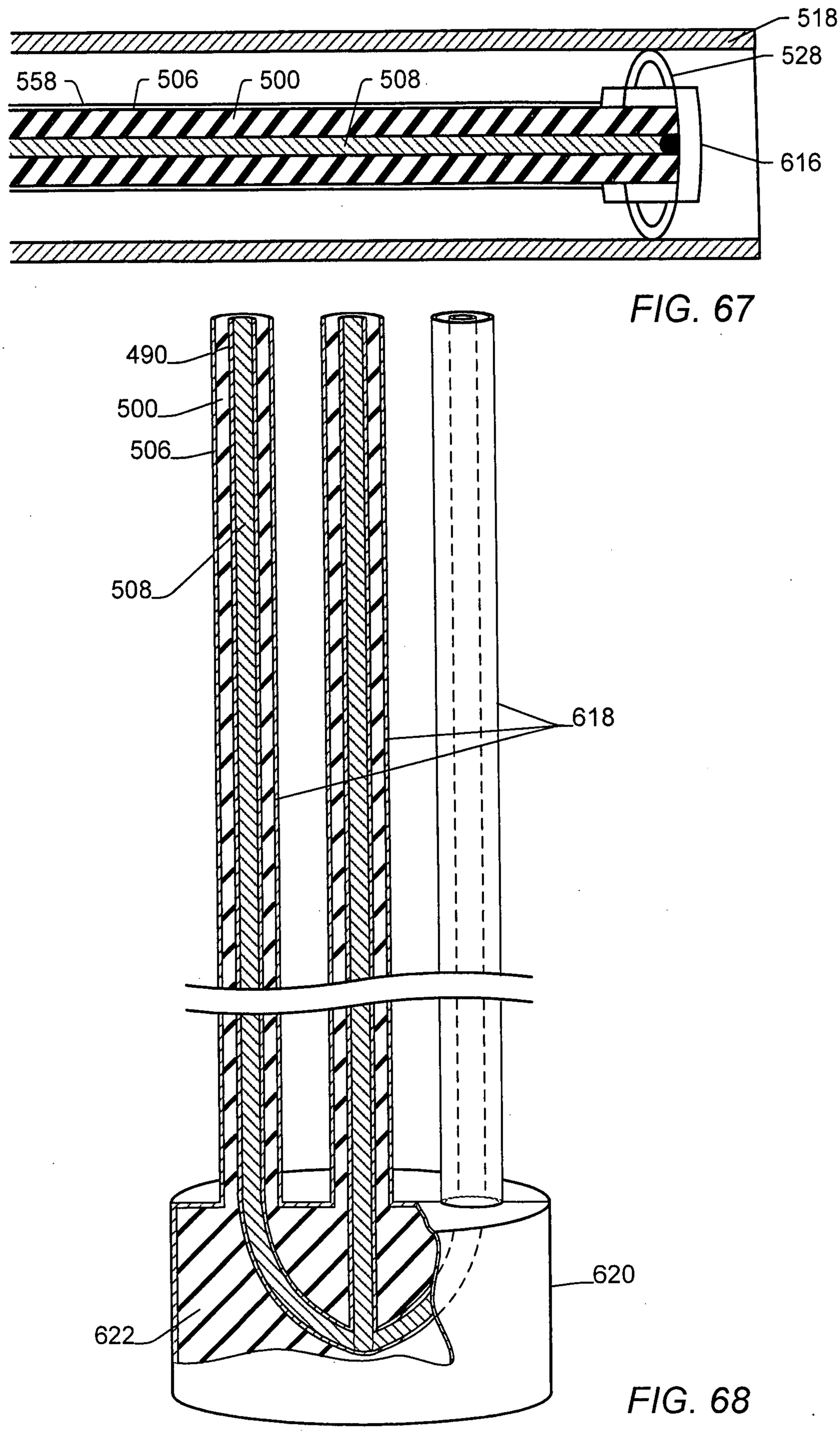


FIG. 67

FIG. 68

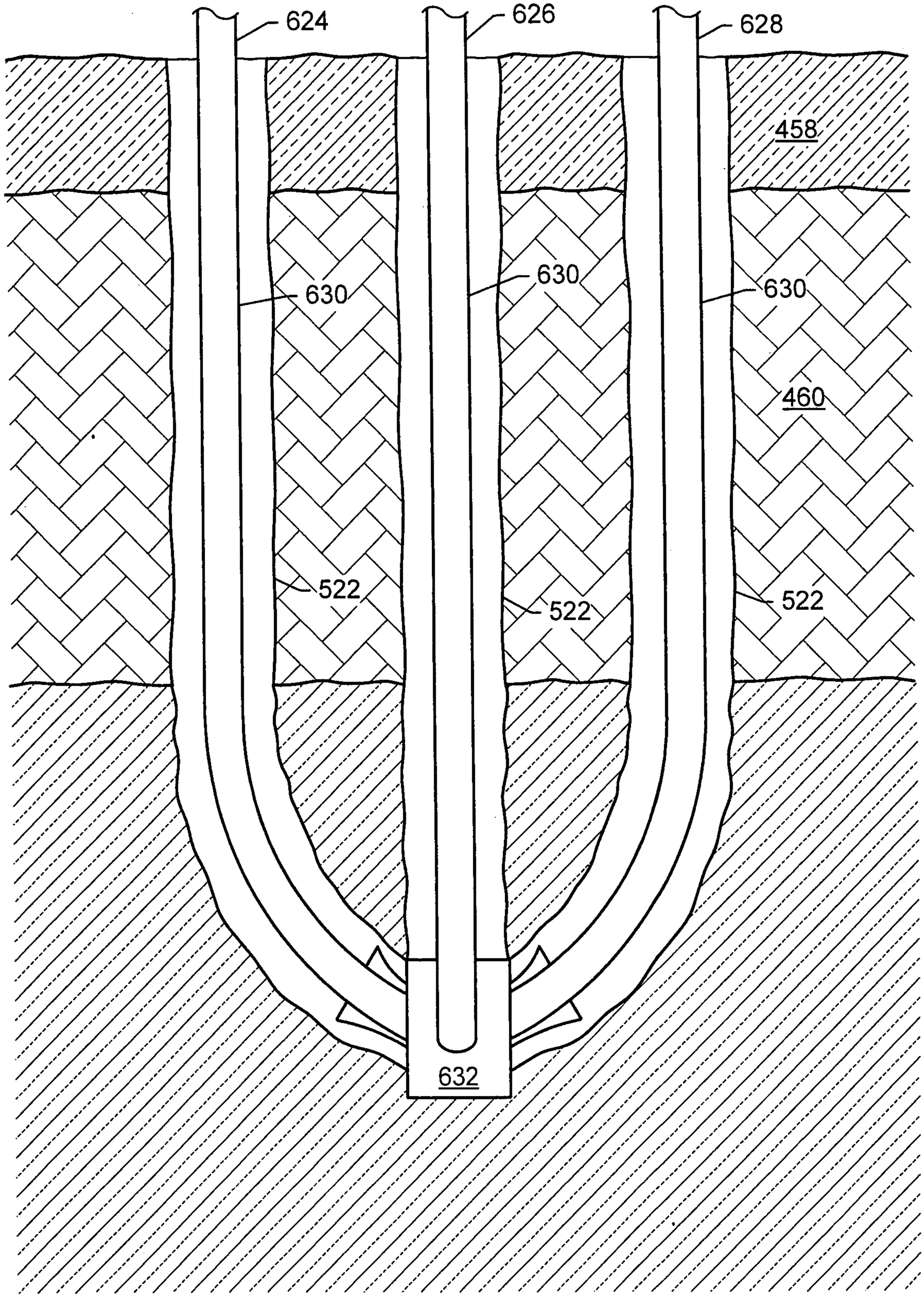


FIG. 69

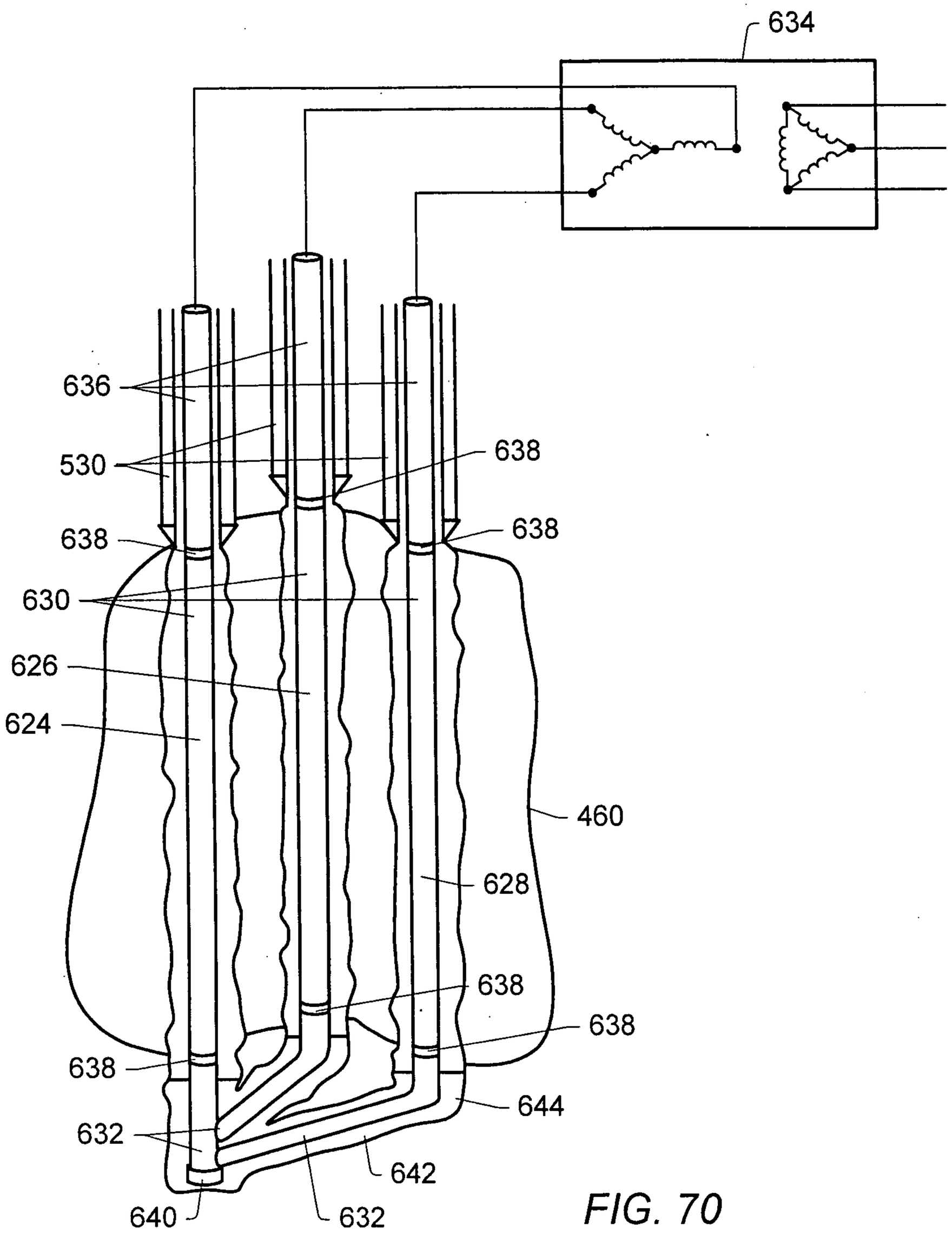

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FIG. 70

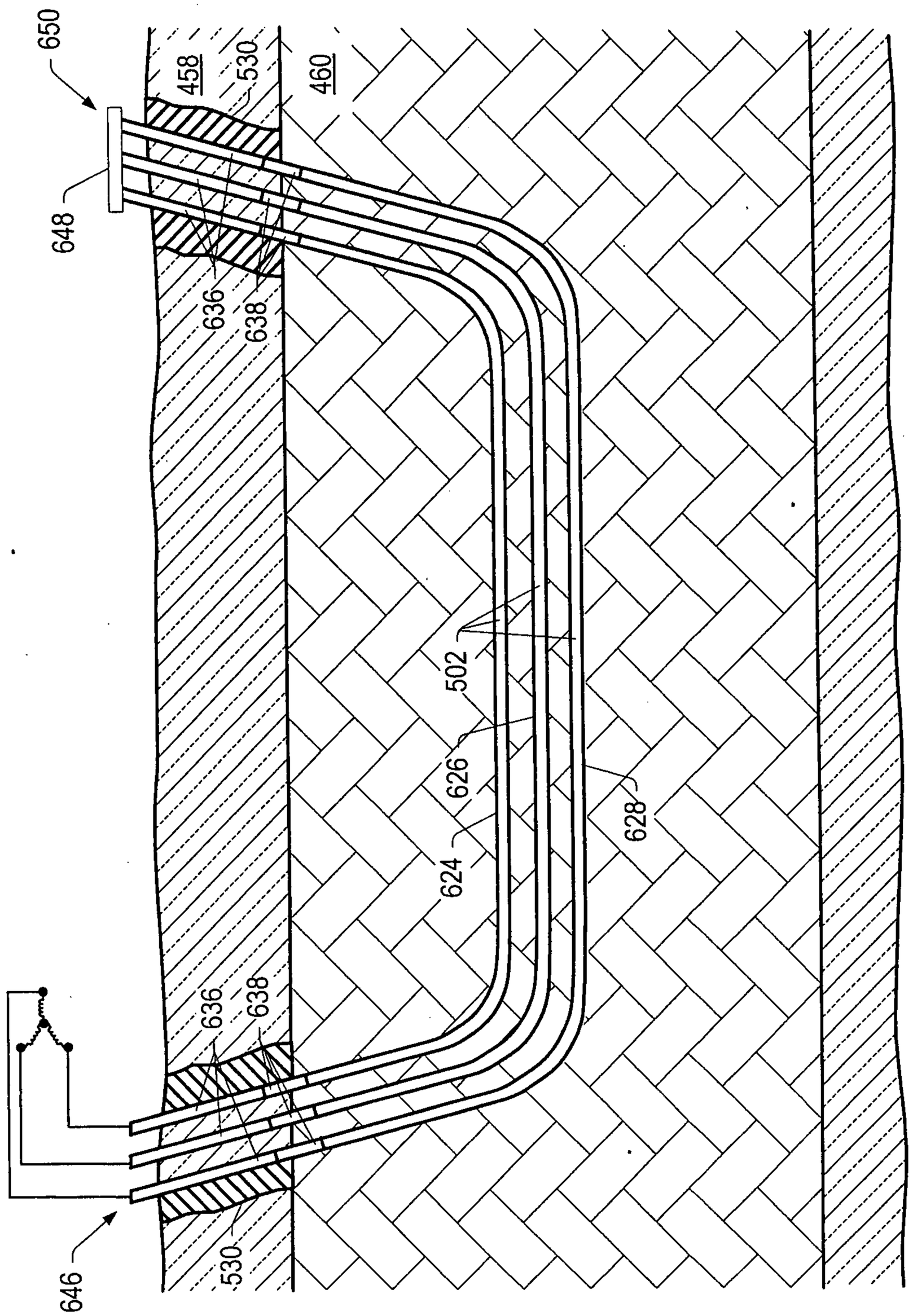


FIG. 71

FIG. 72

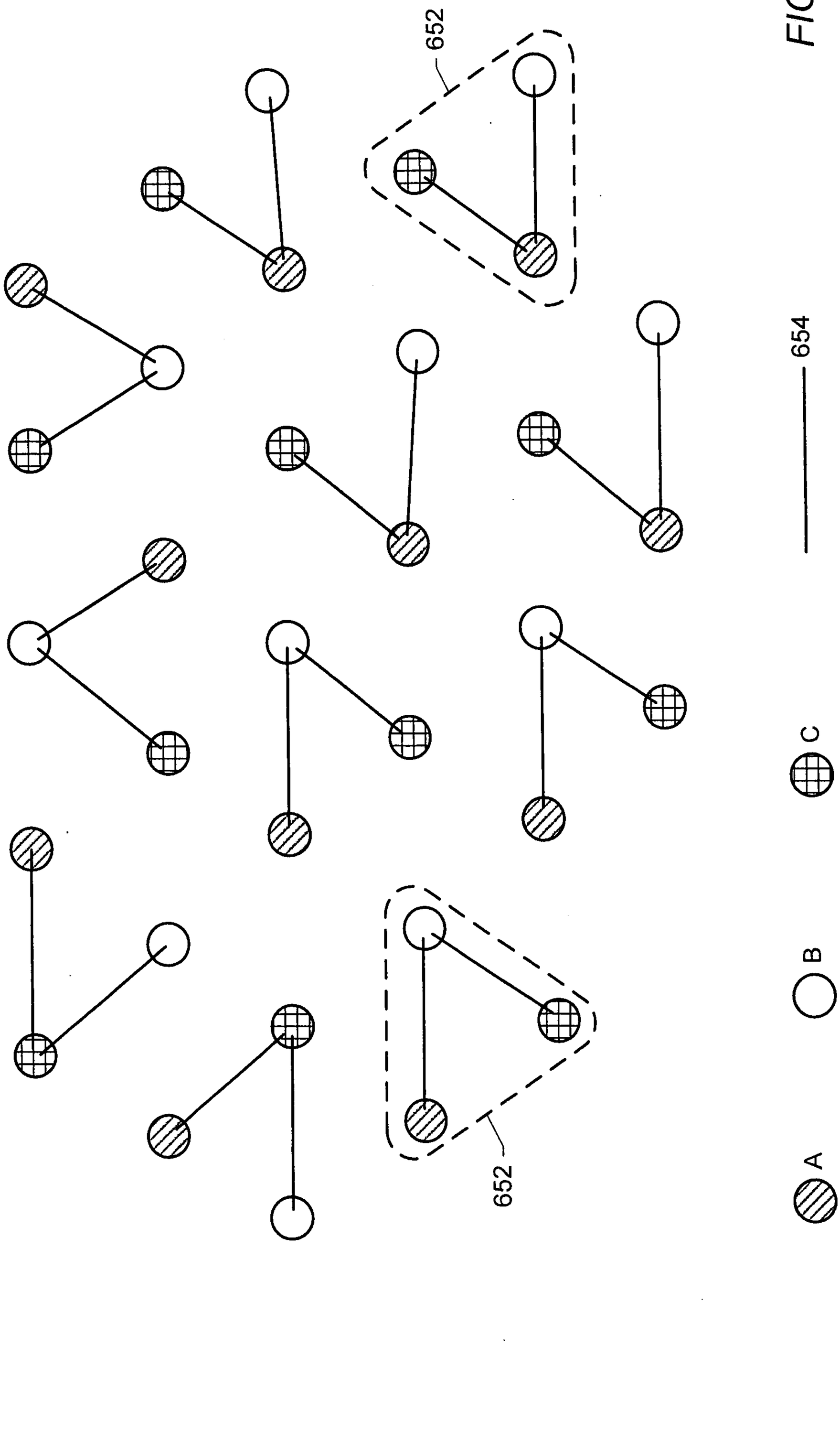
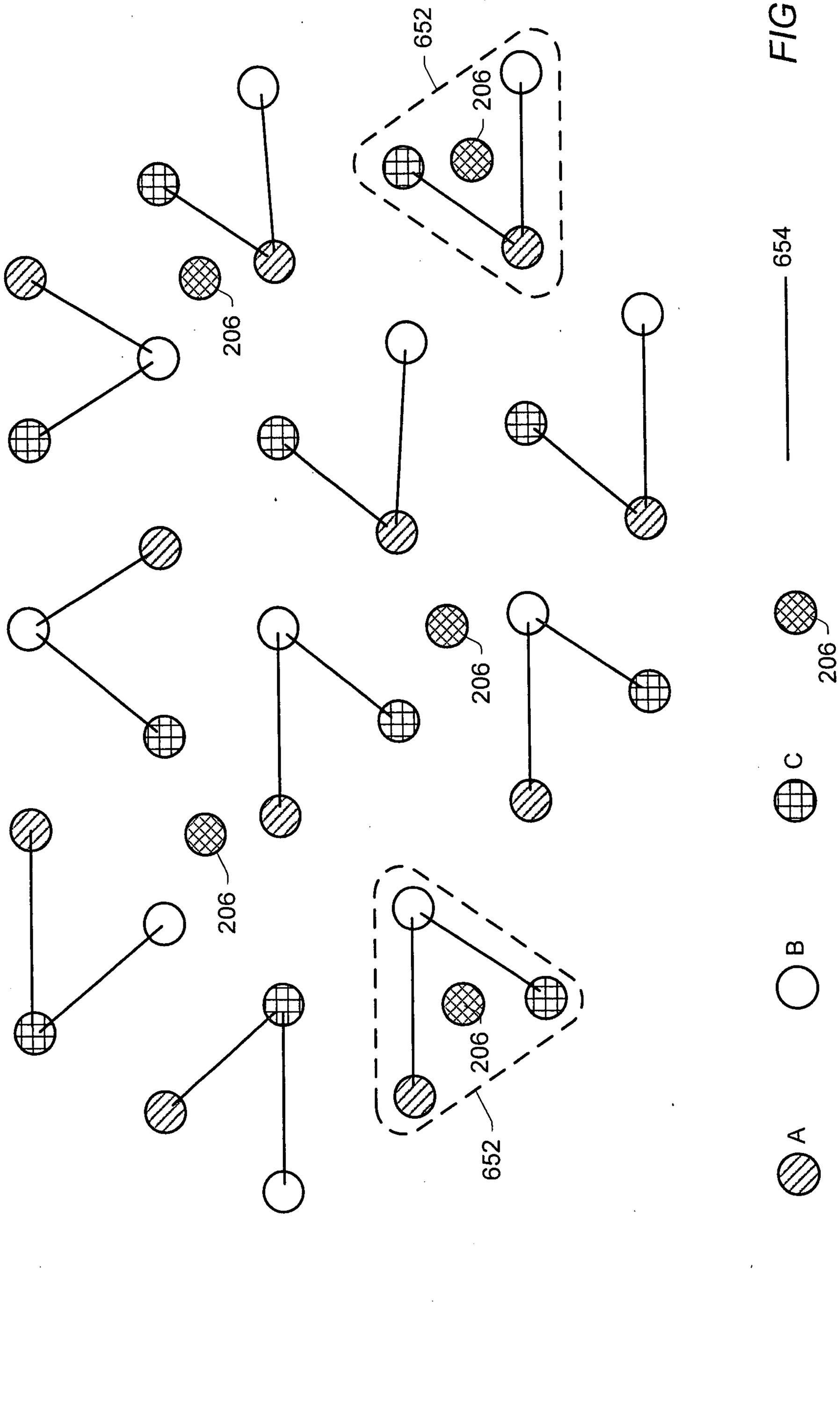


FIG. 73



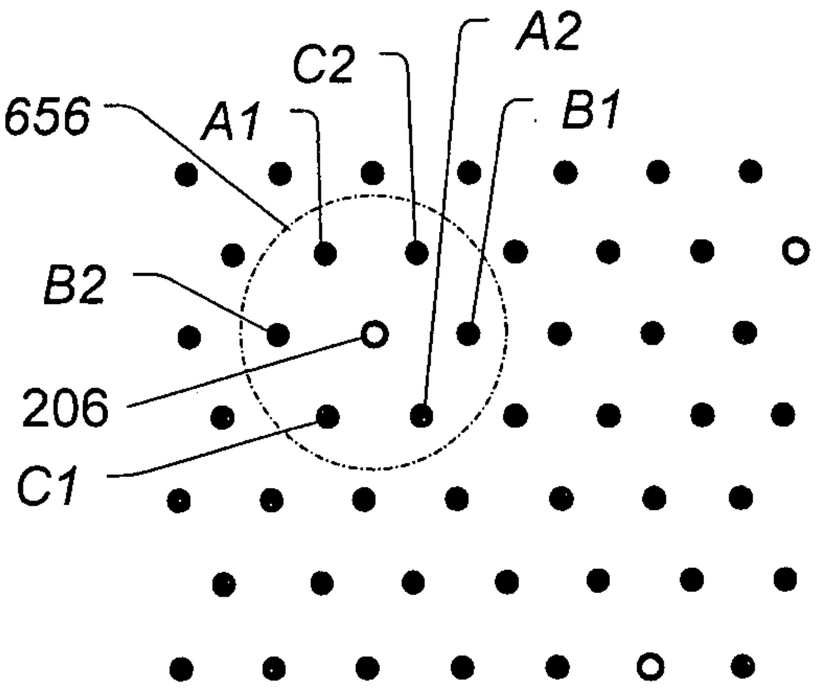


FIG. 74

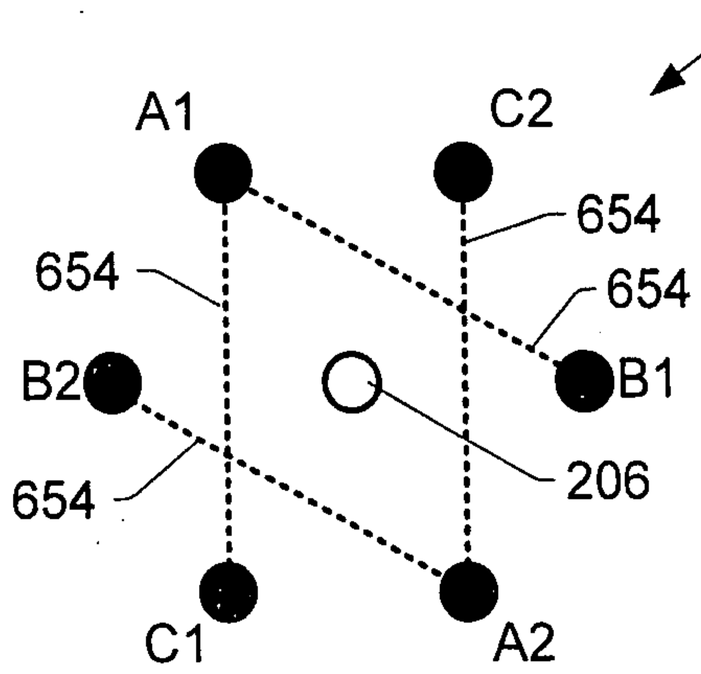


FIG. 75

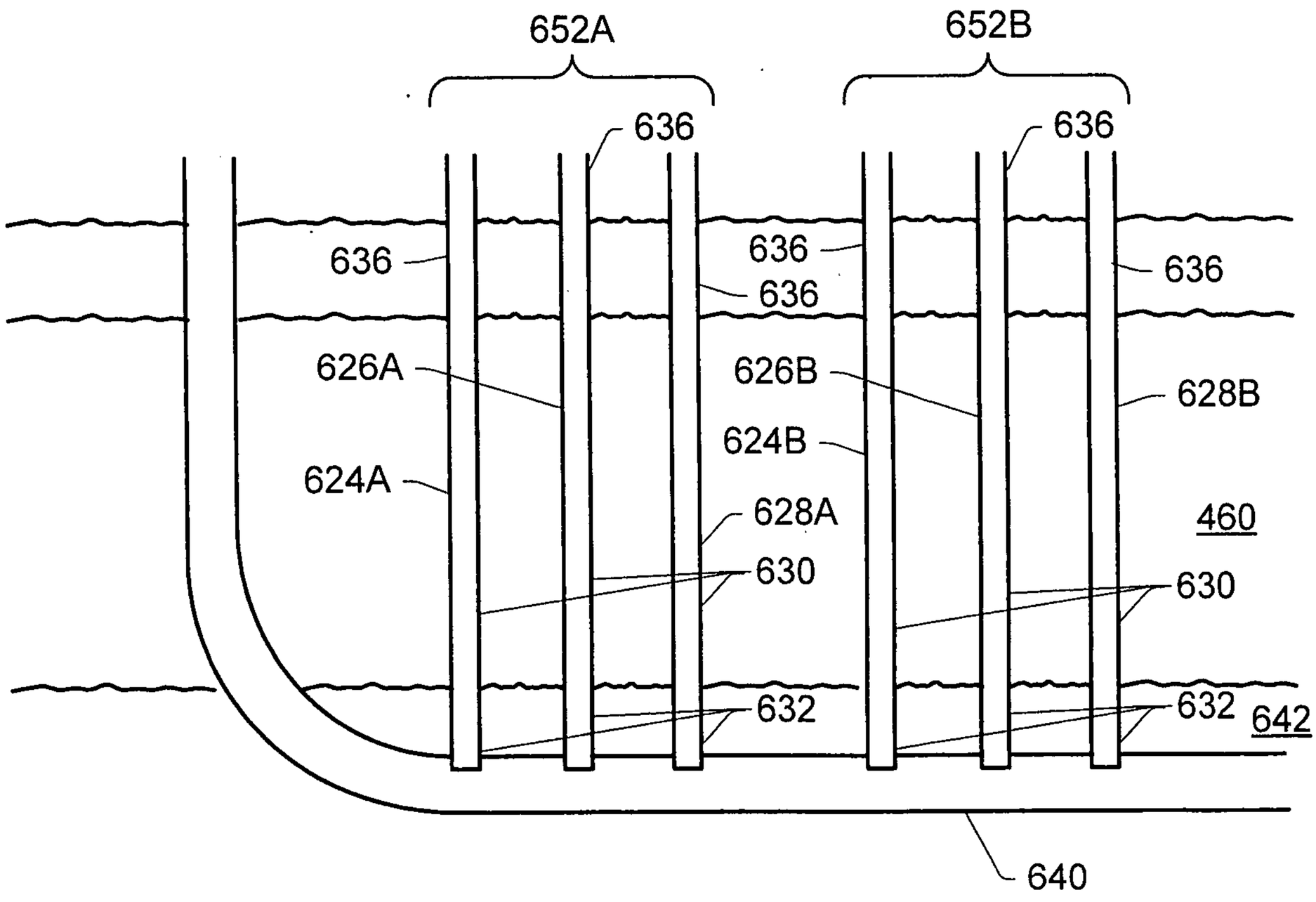


FIG. 76

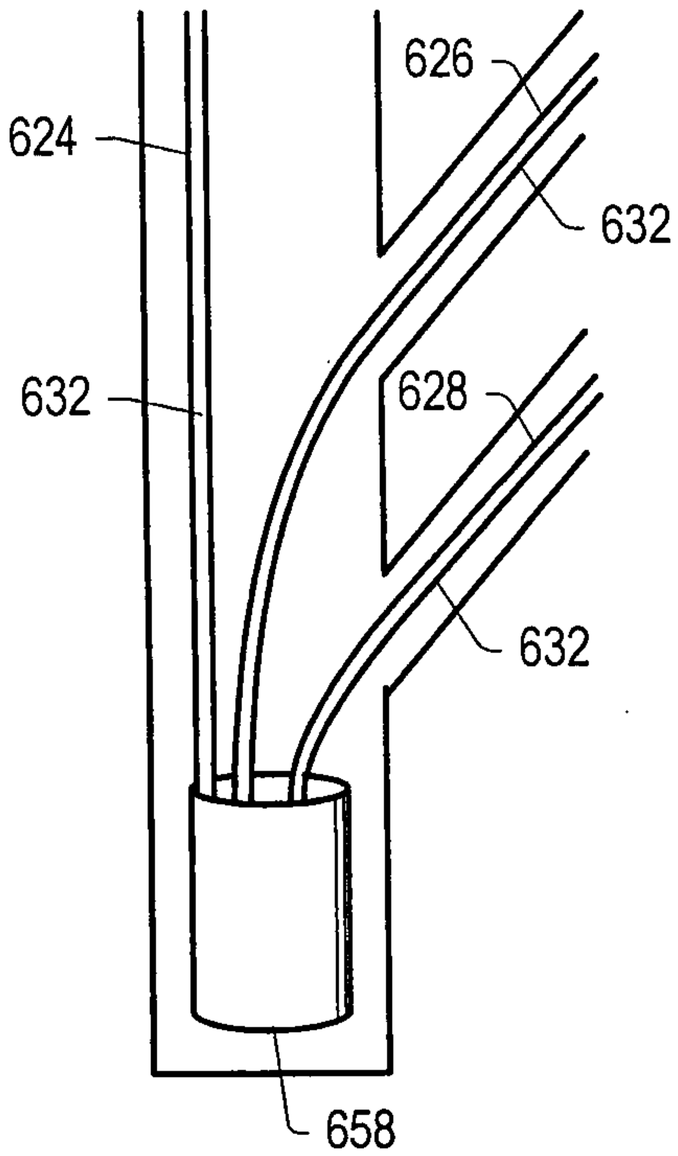


FIG. 77

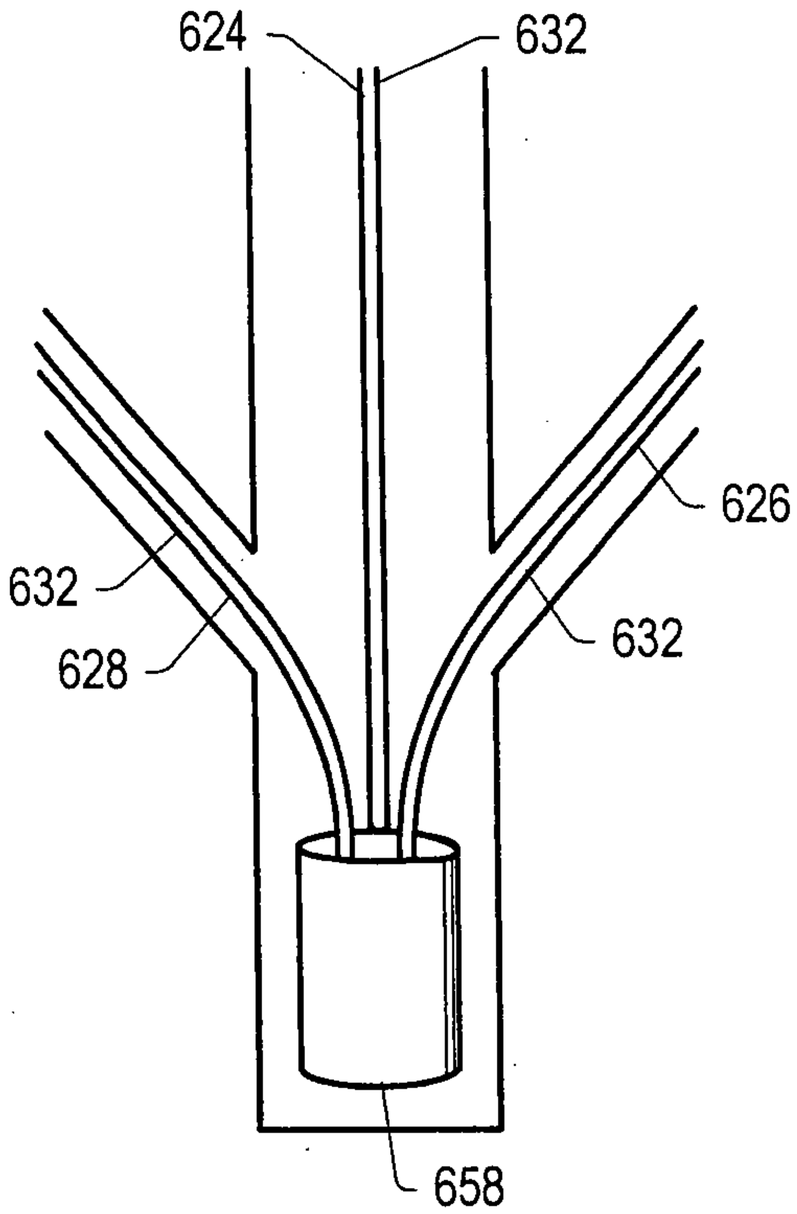


FIG. 78

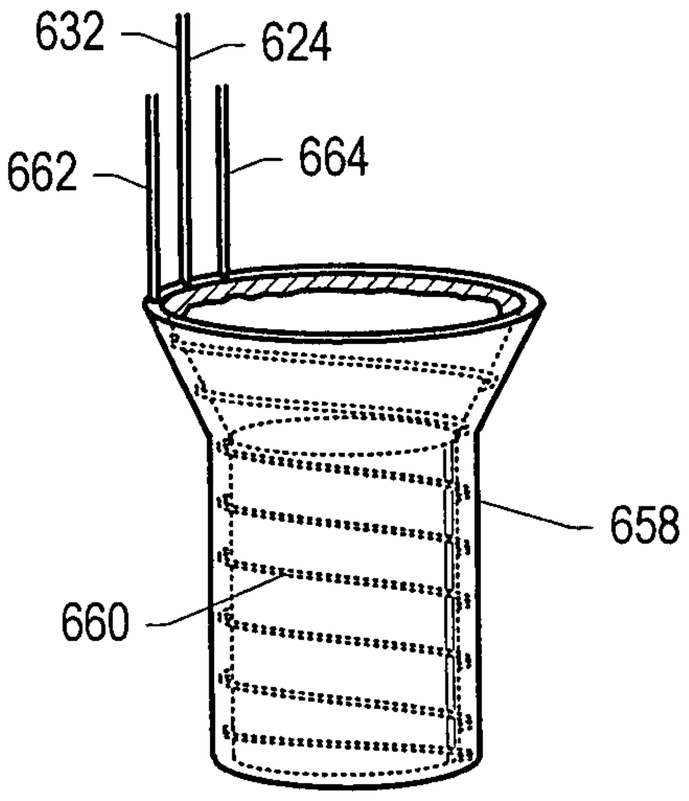


FIG. 79

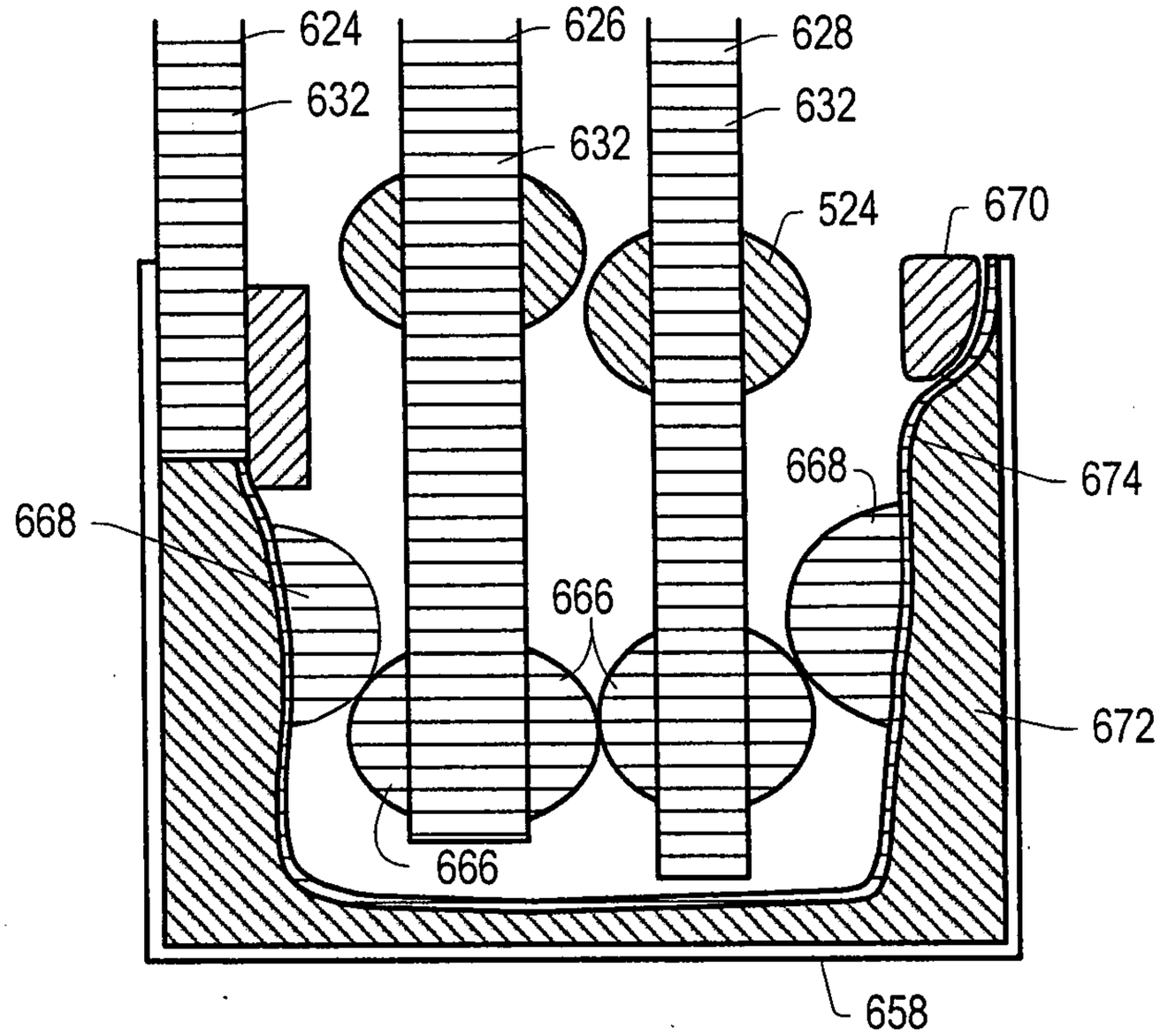


FIG. 80

FIG. 81

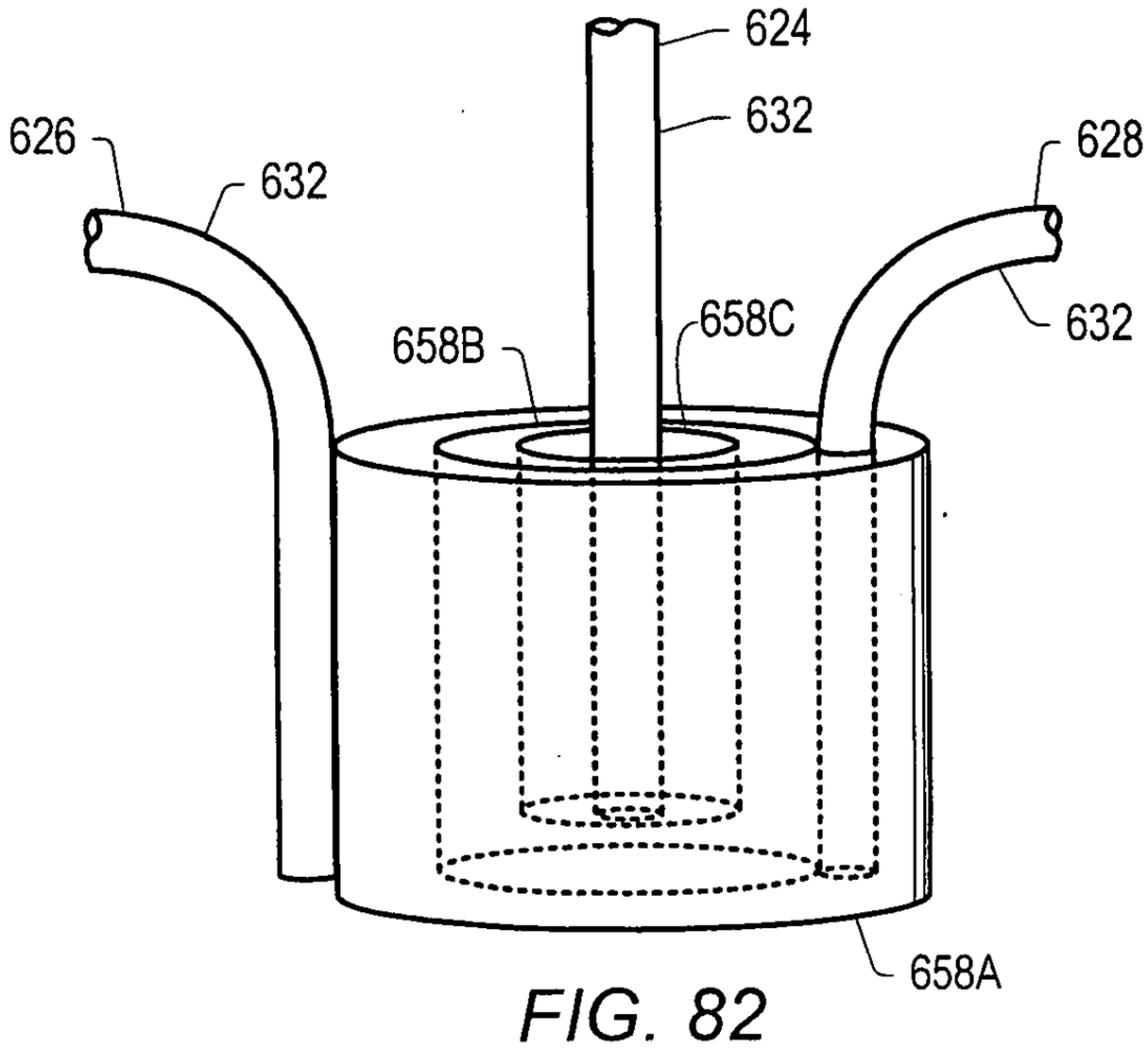


FIG. 82

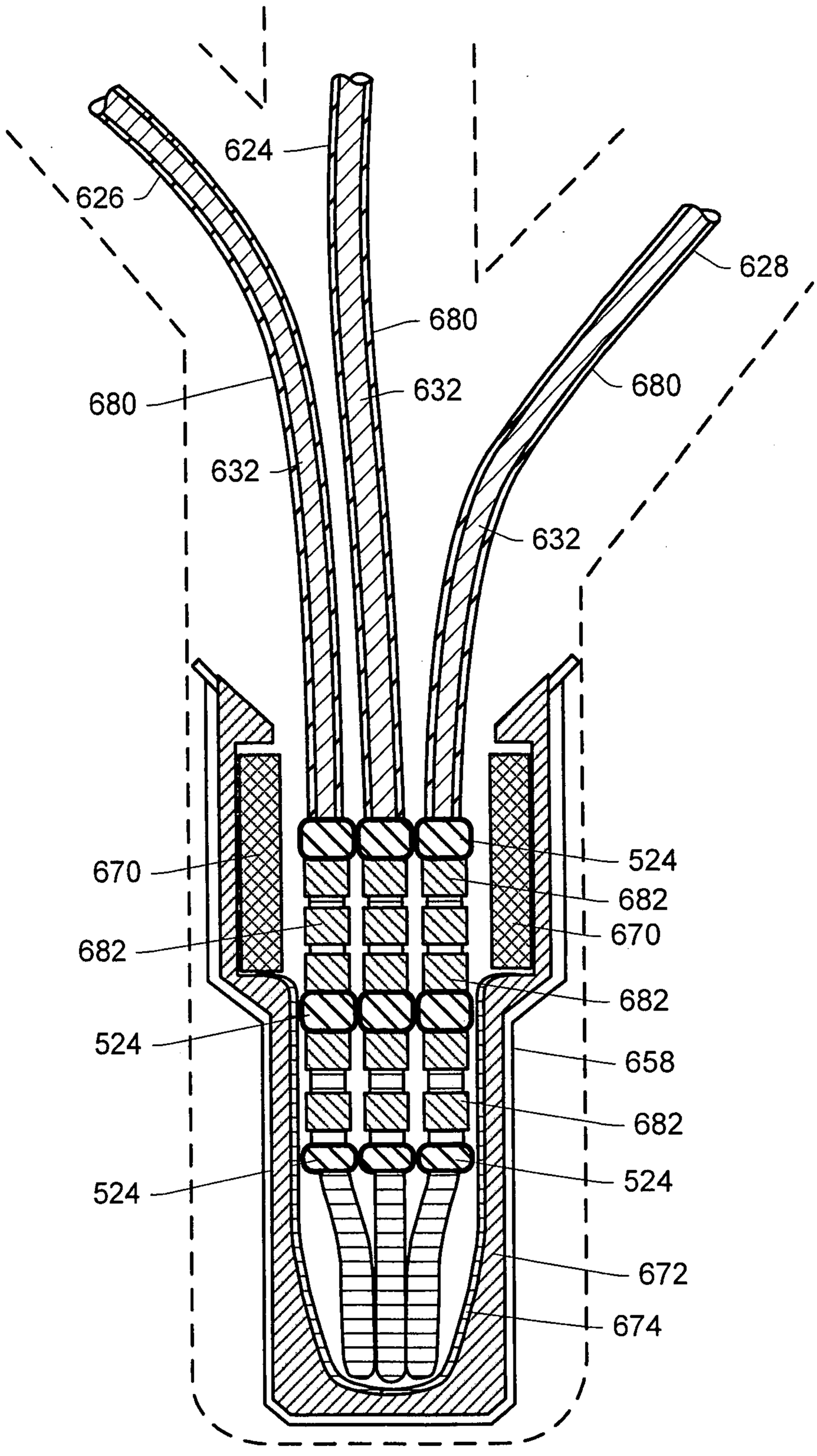

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FIG. 83

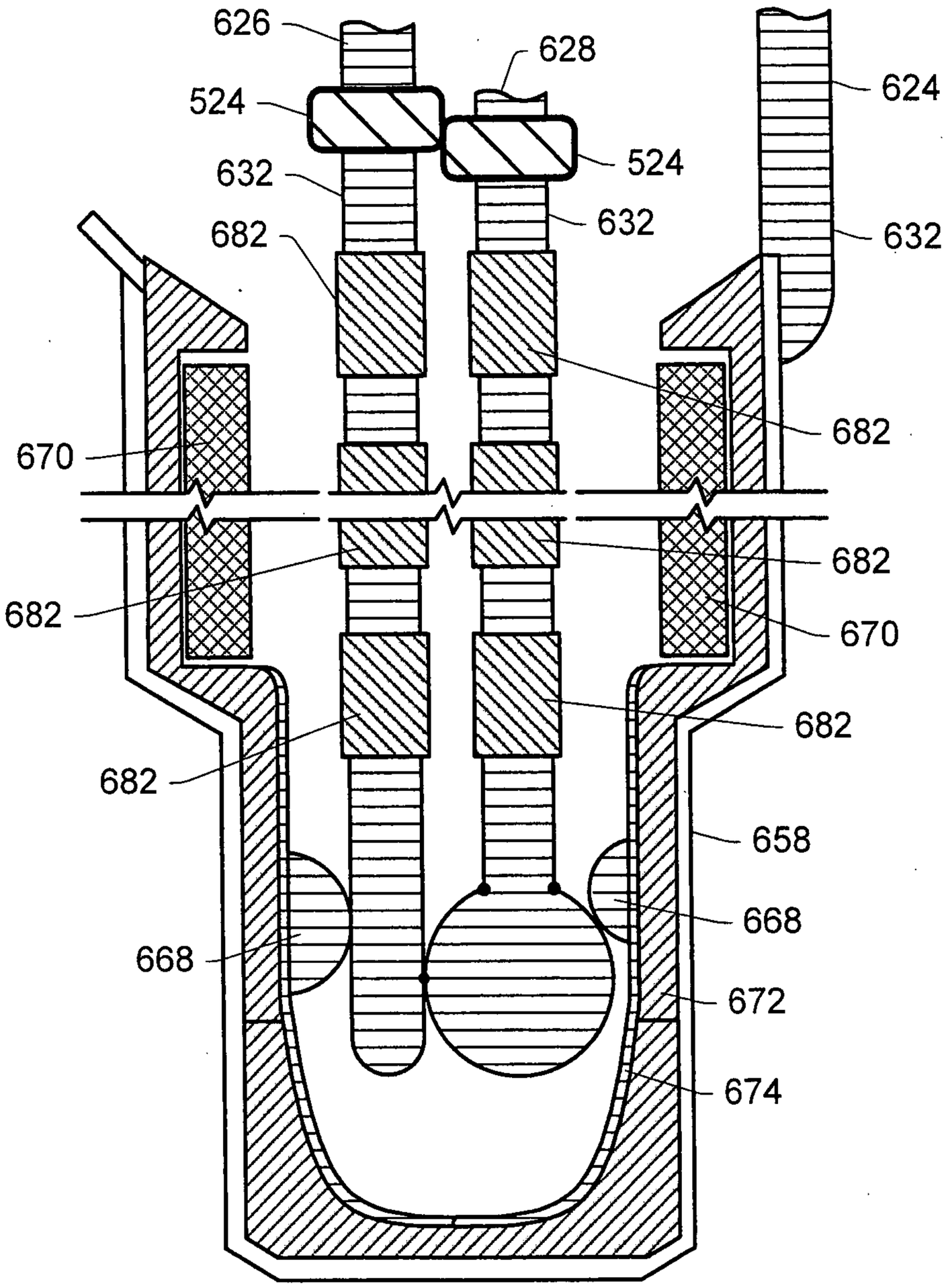

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FIG. 84

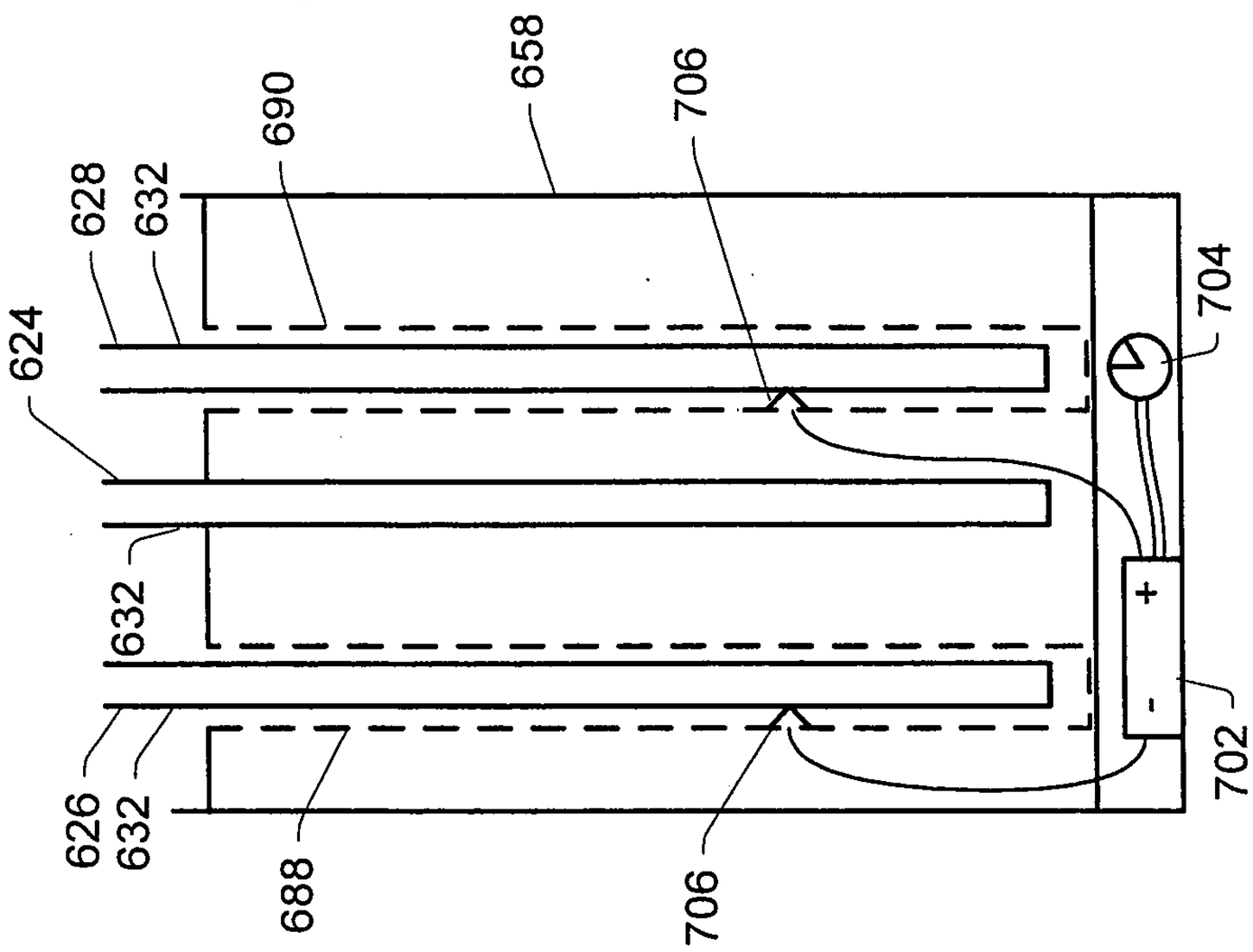

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FIG. 86

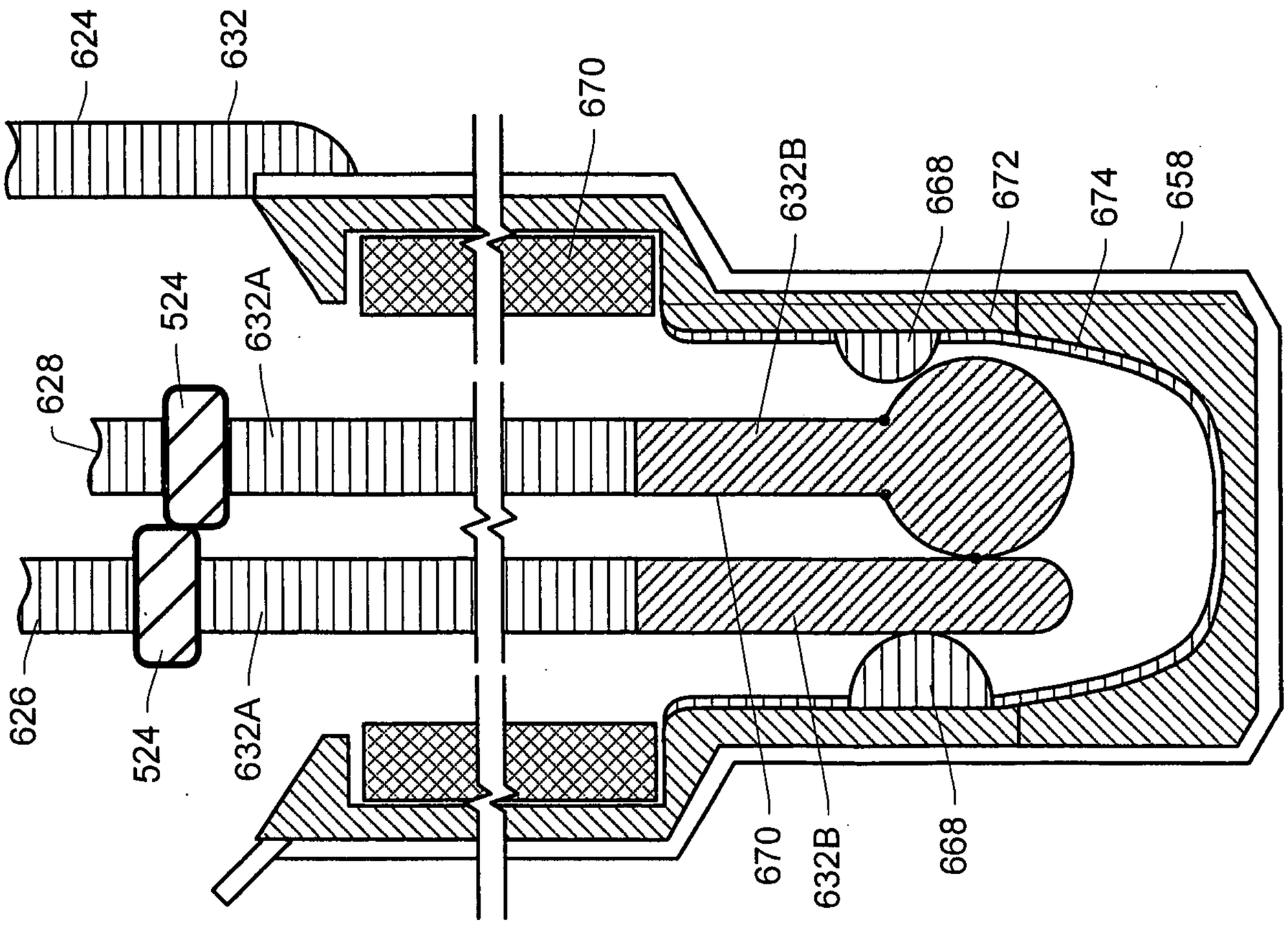

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FIG. 85

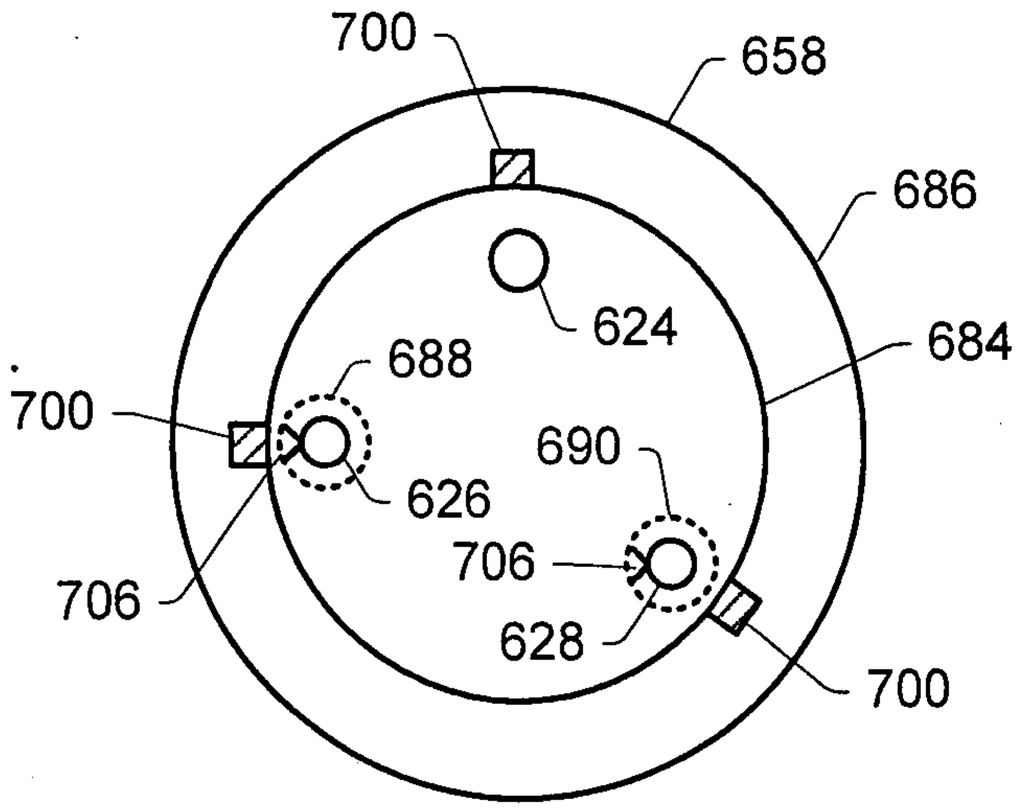


FIG. 87

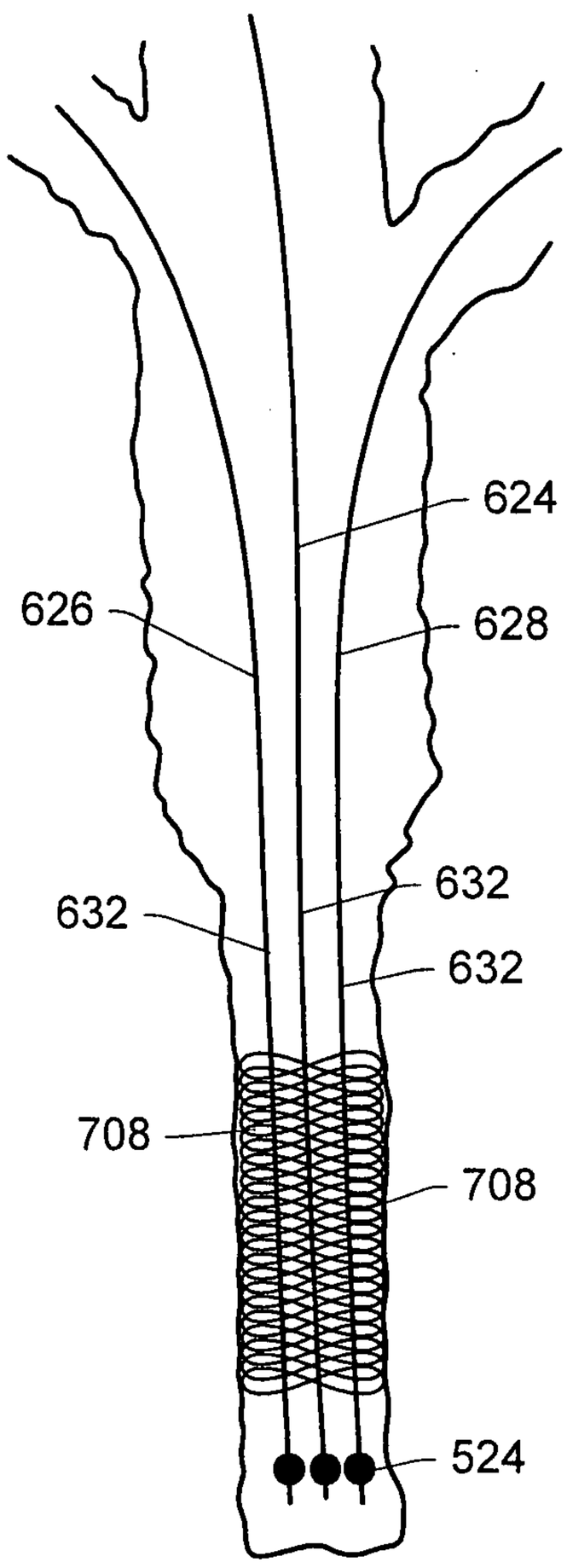


FIG. 89

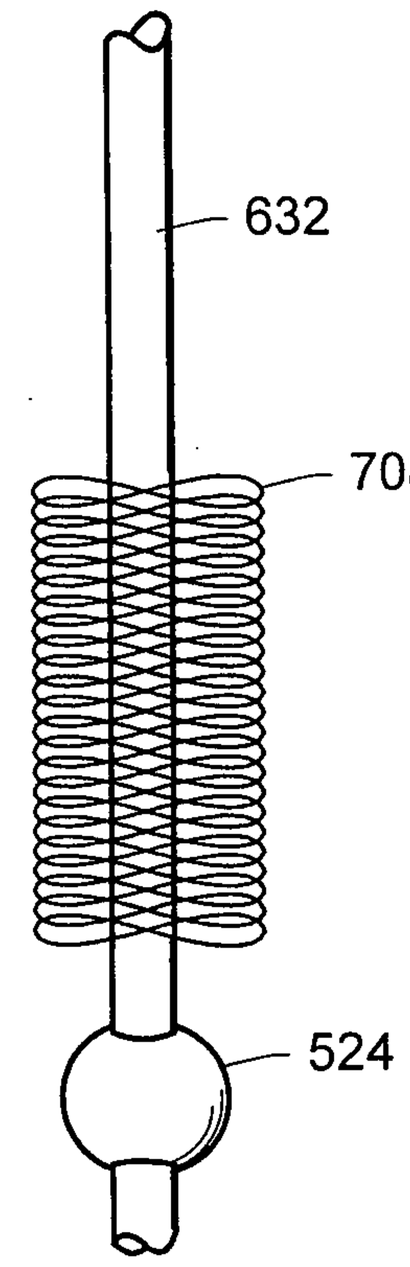


FIG. 88

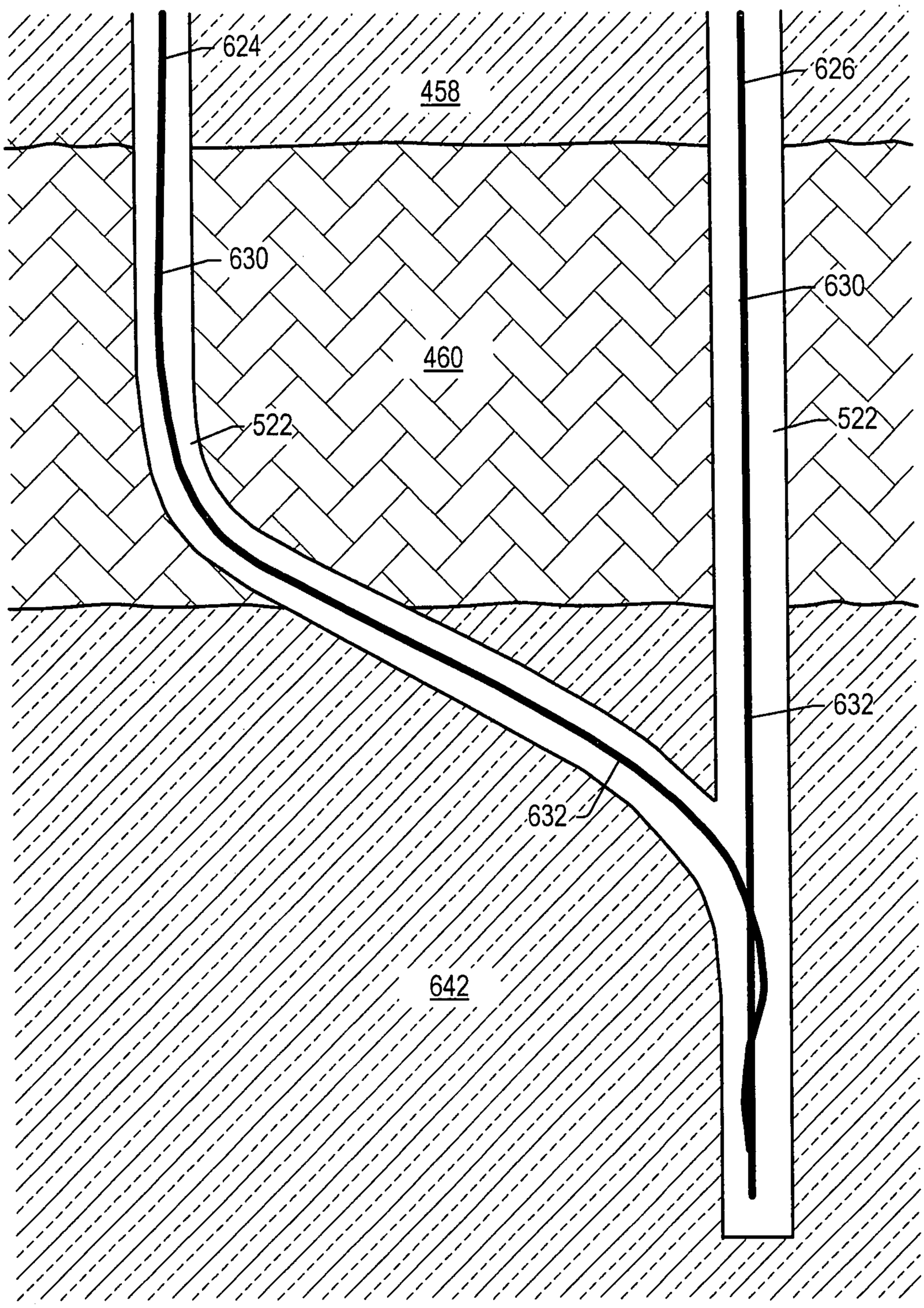


FIG. 90

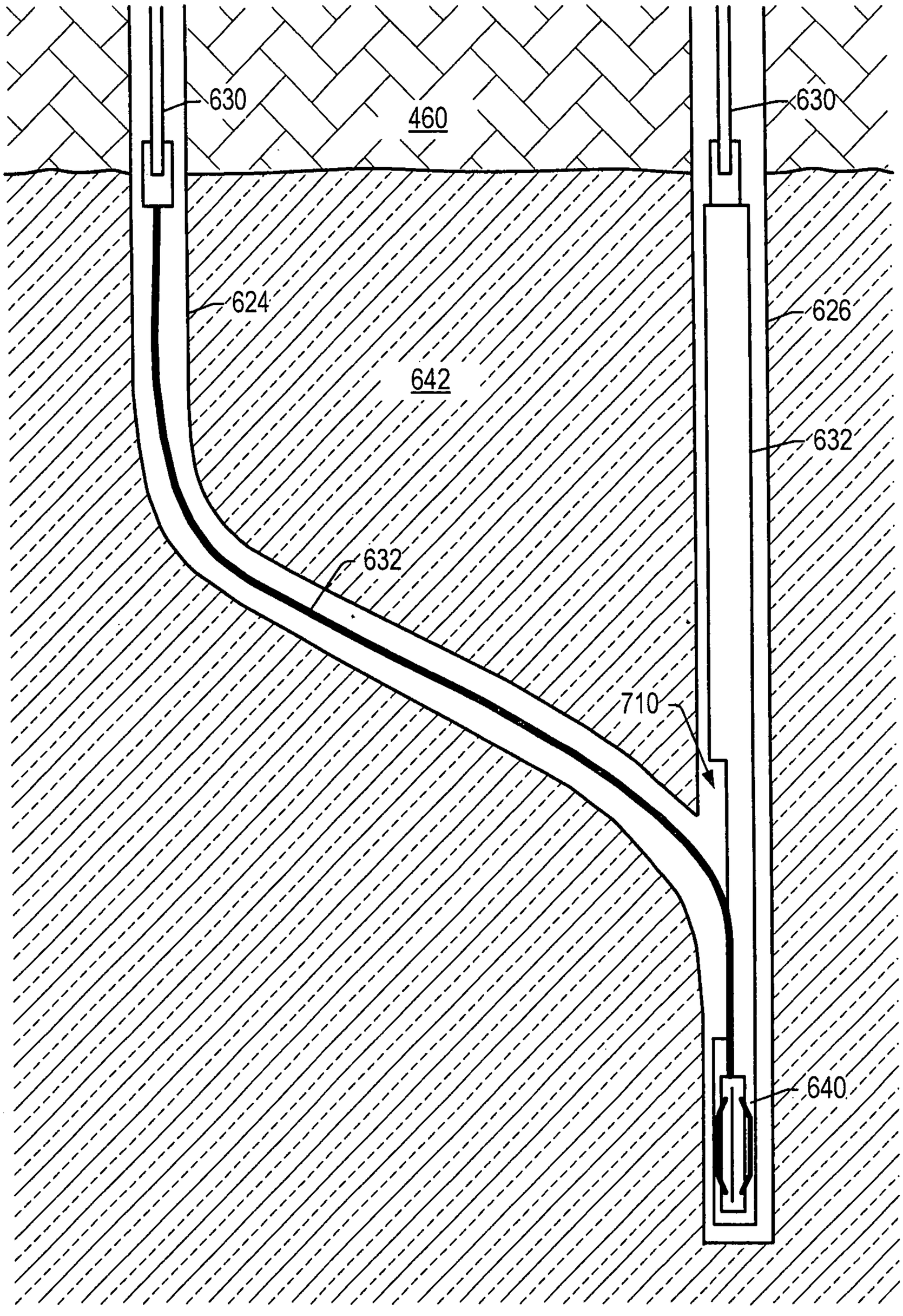


FIG. 91

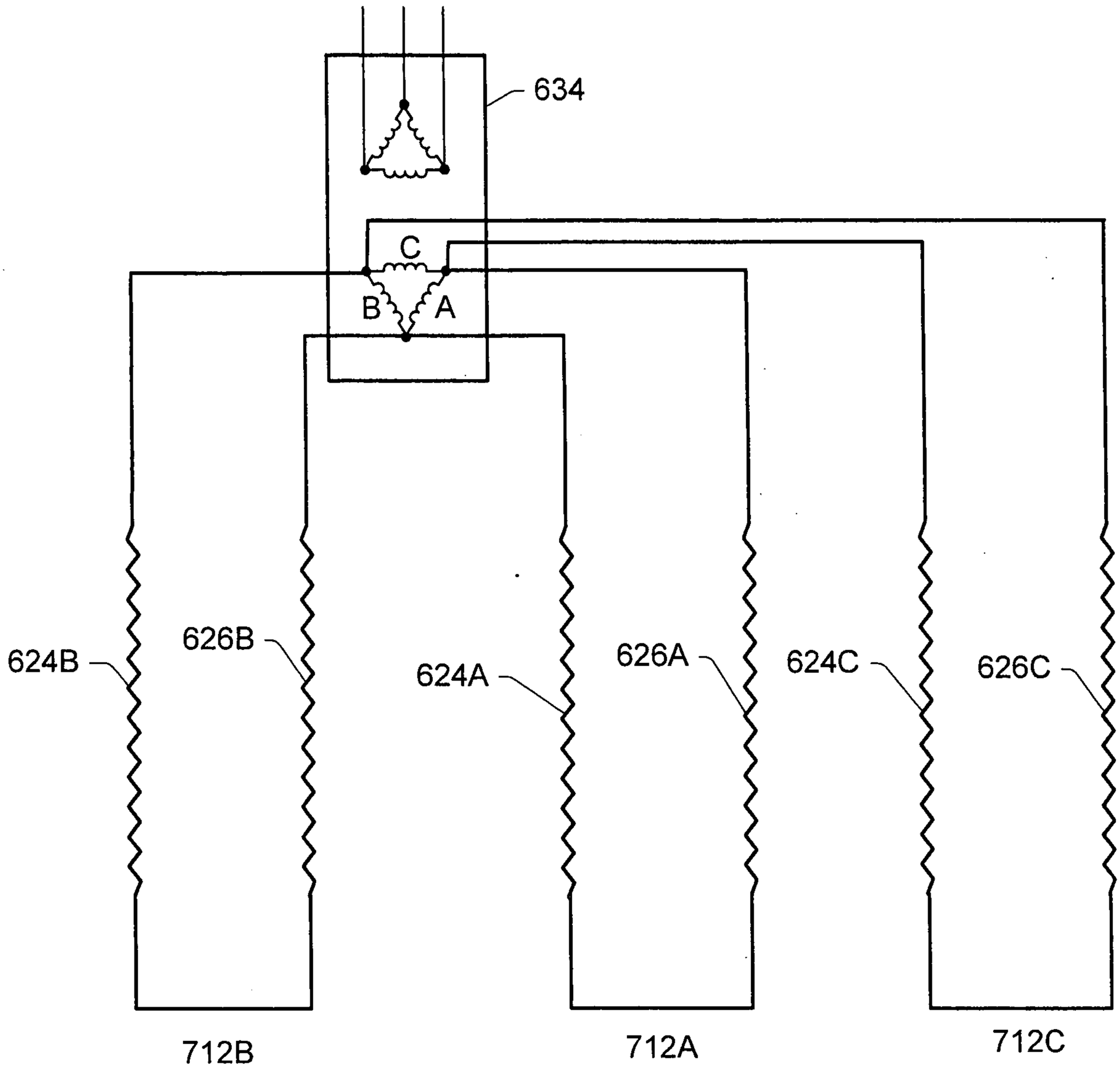


FIG. 92

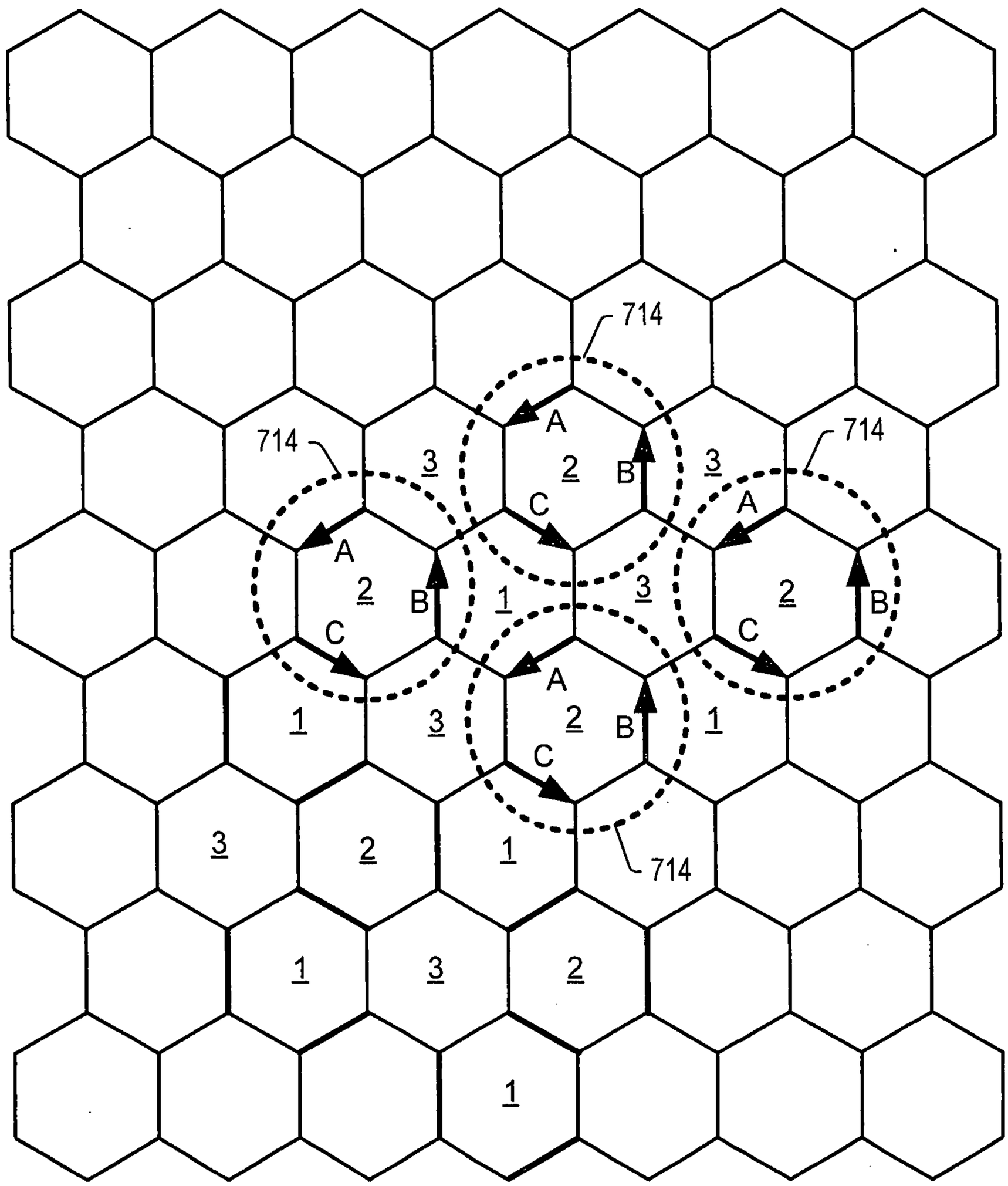


FIG. 93

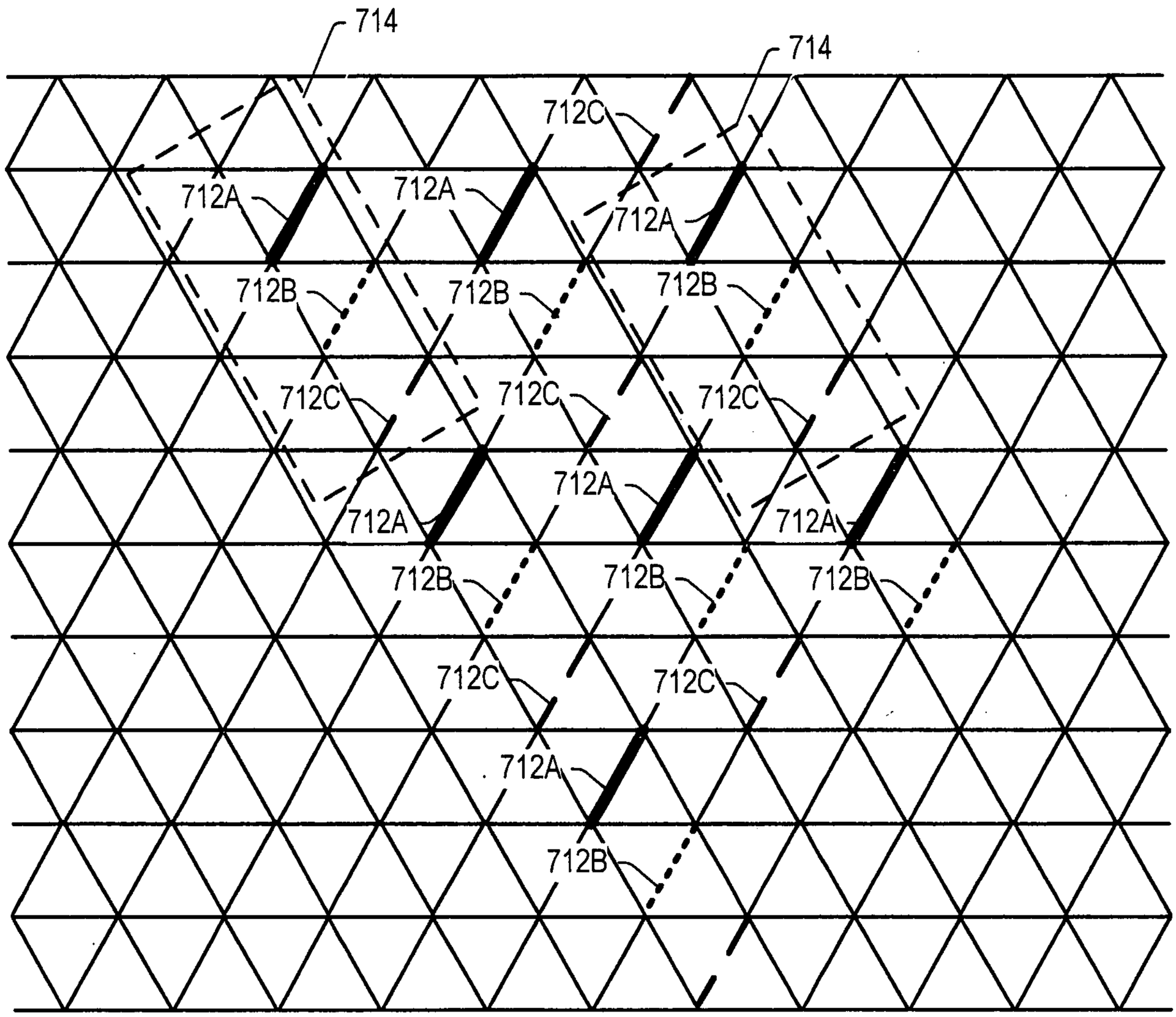

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FIG. 94

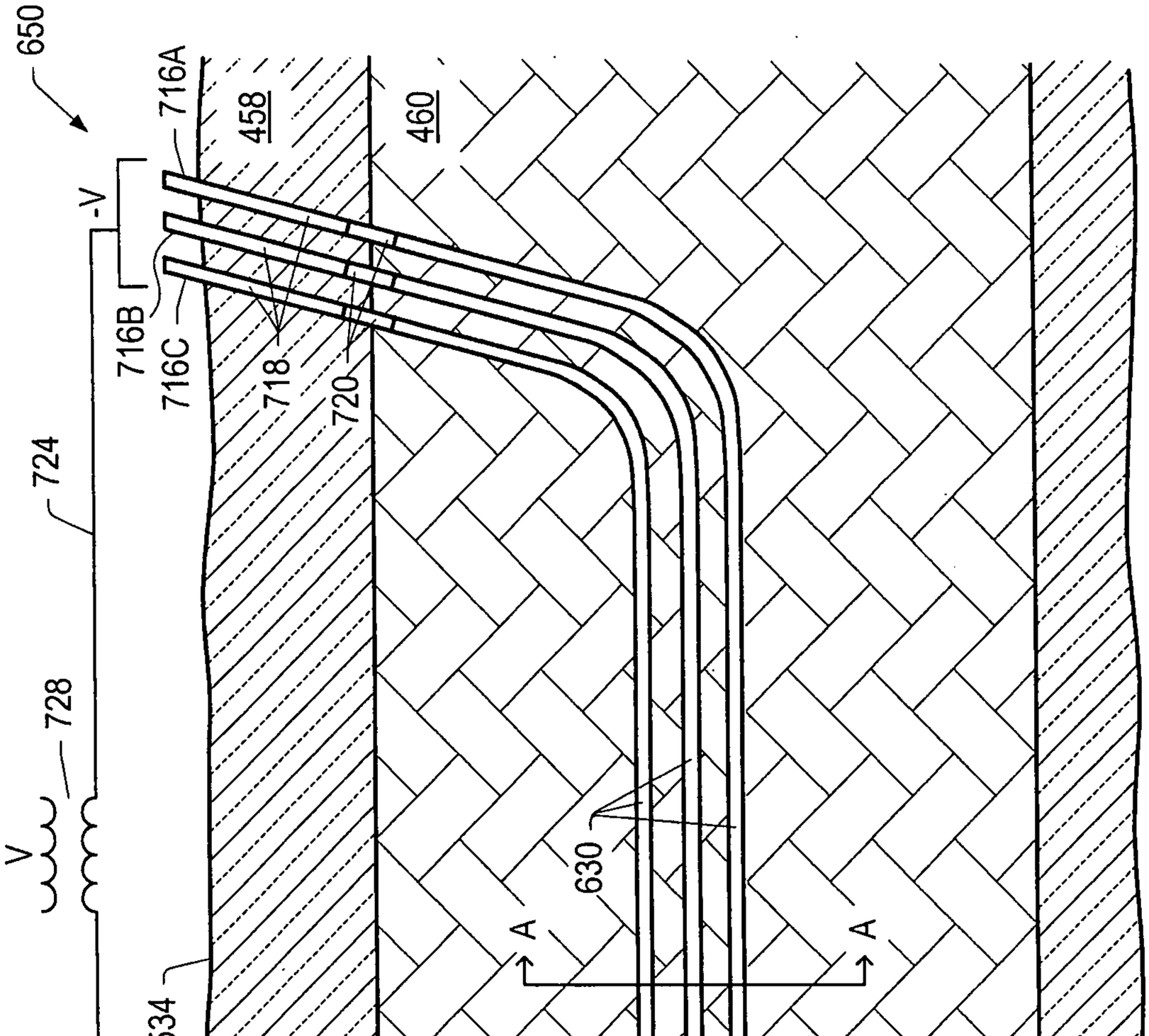

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FIG. 95

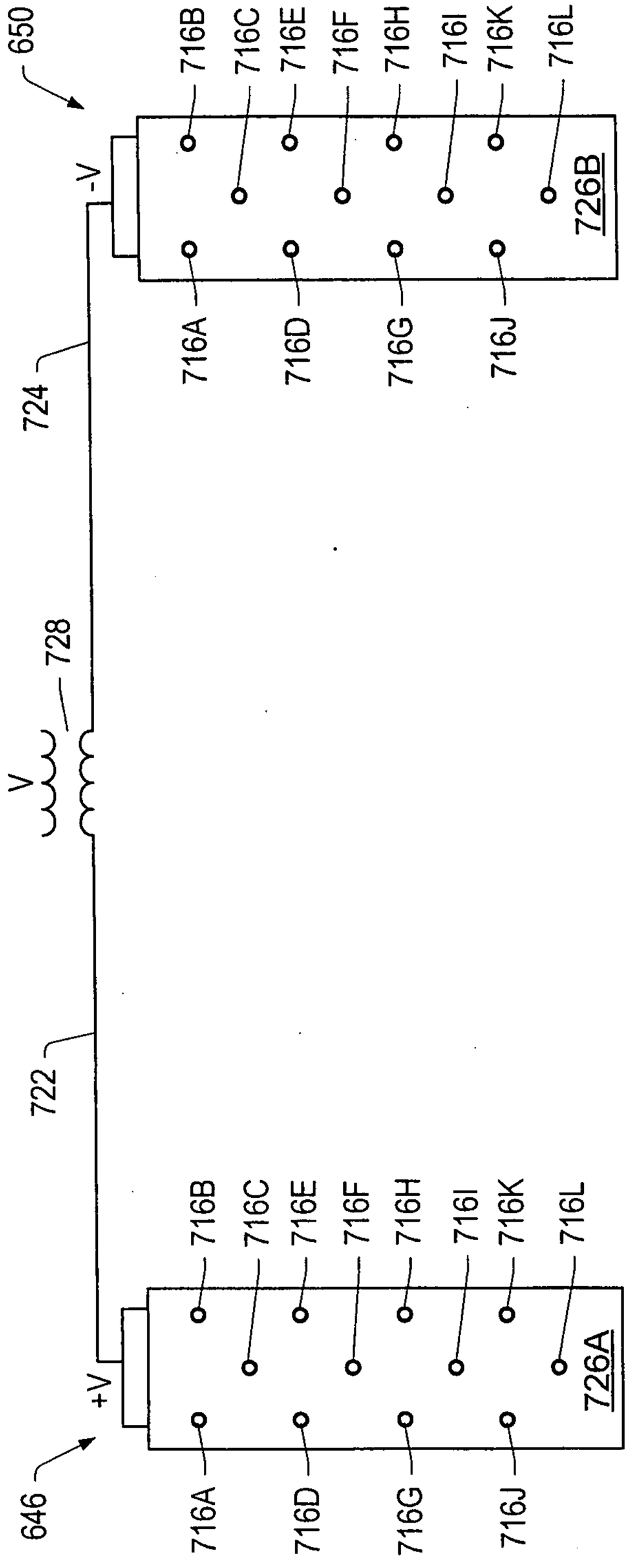

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FIG. 96

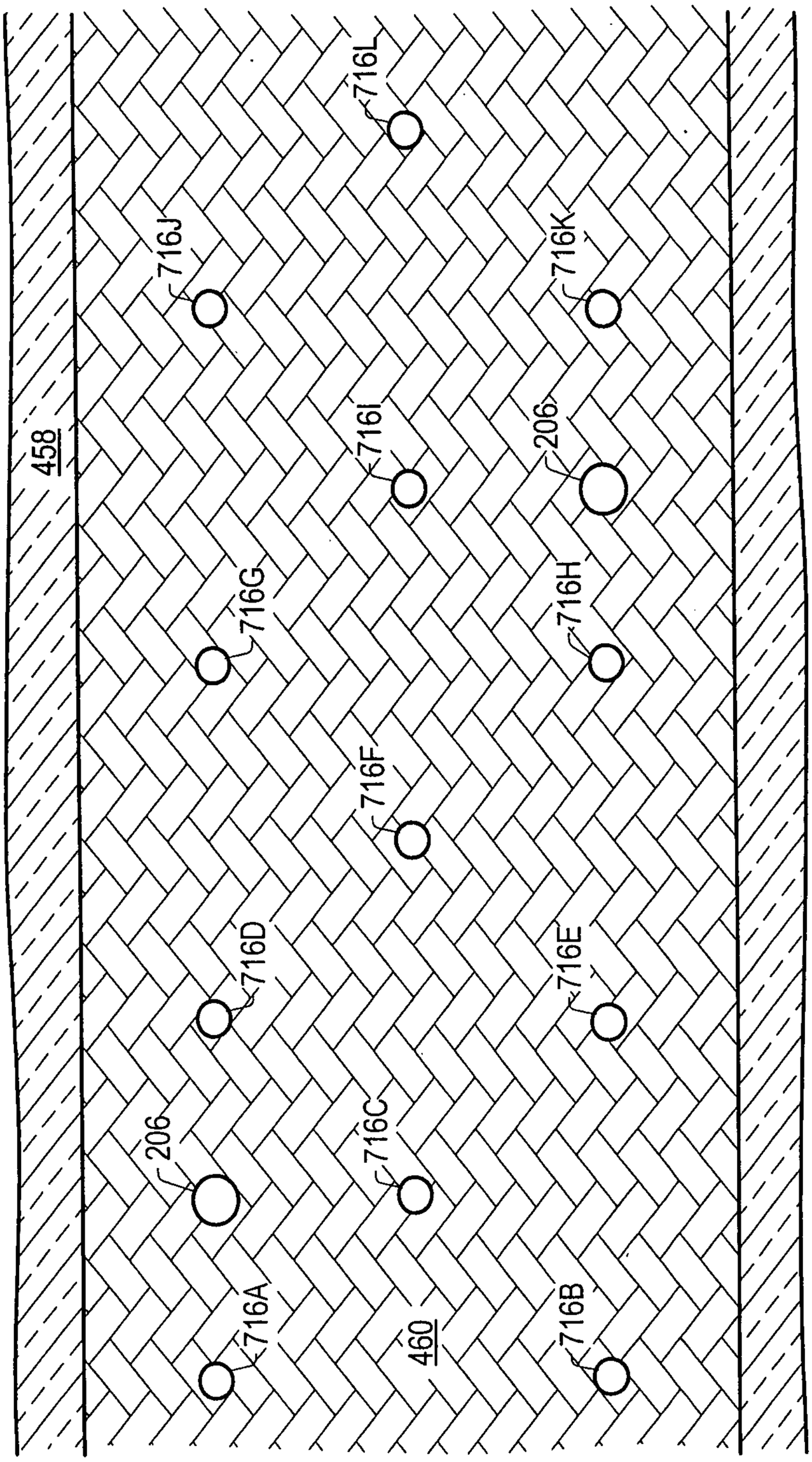

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FIG. 97

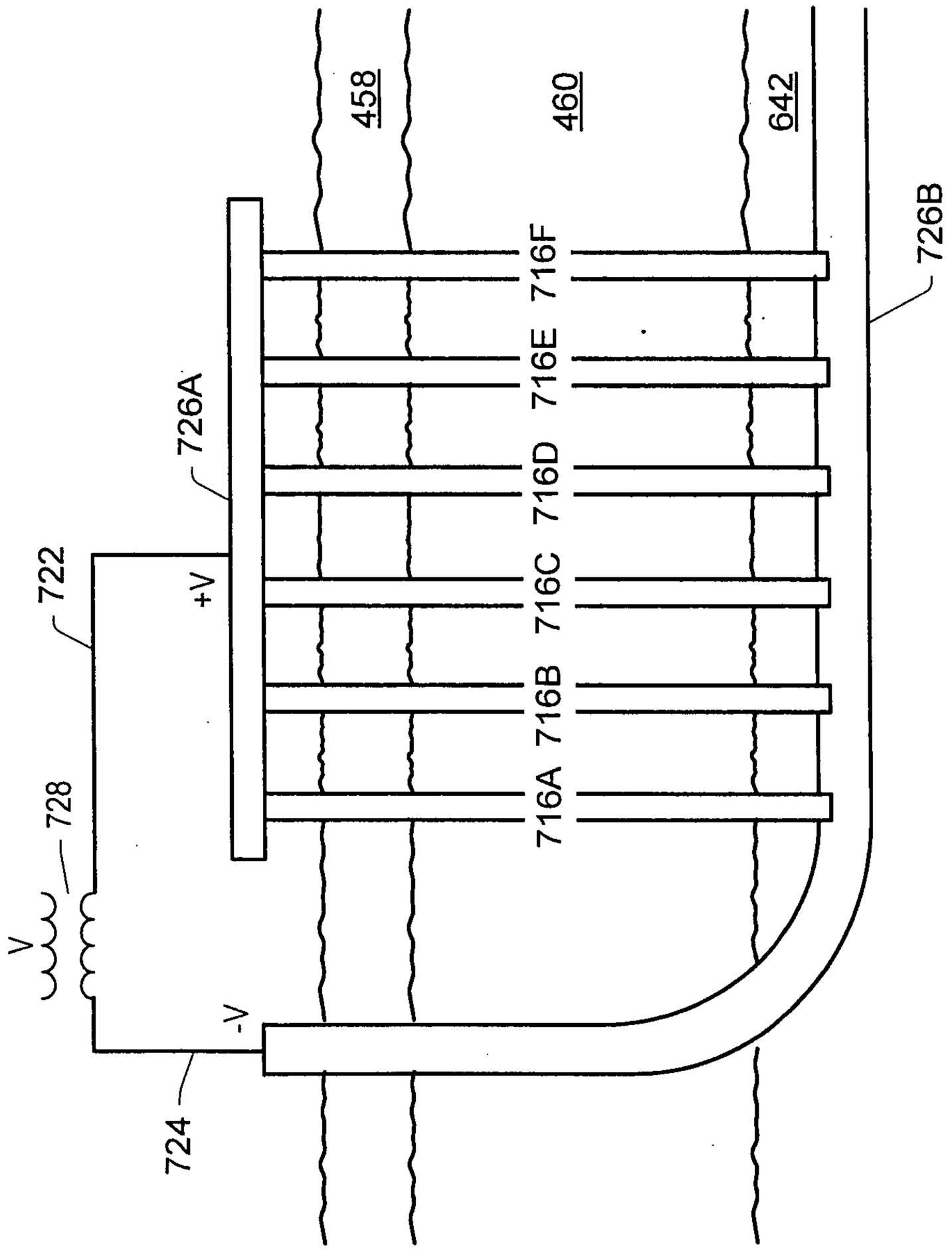

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FIG. 98

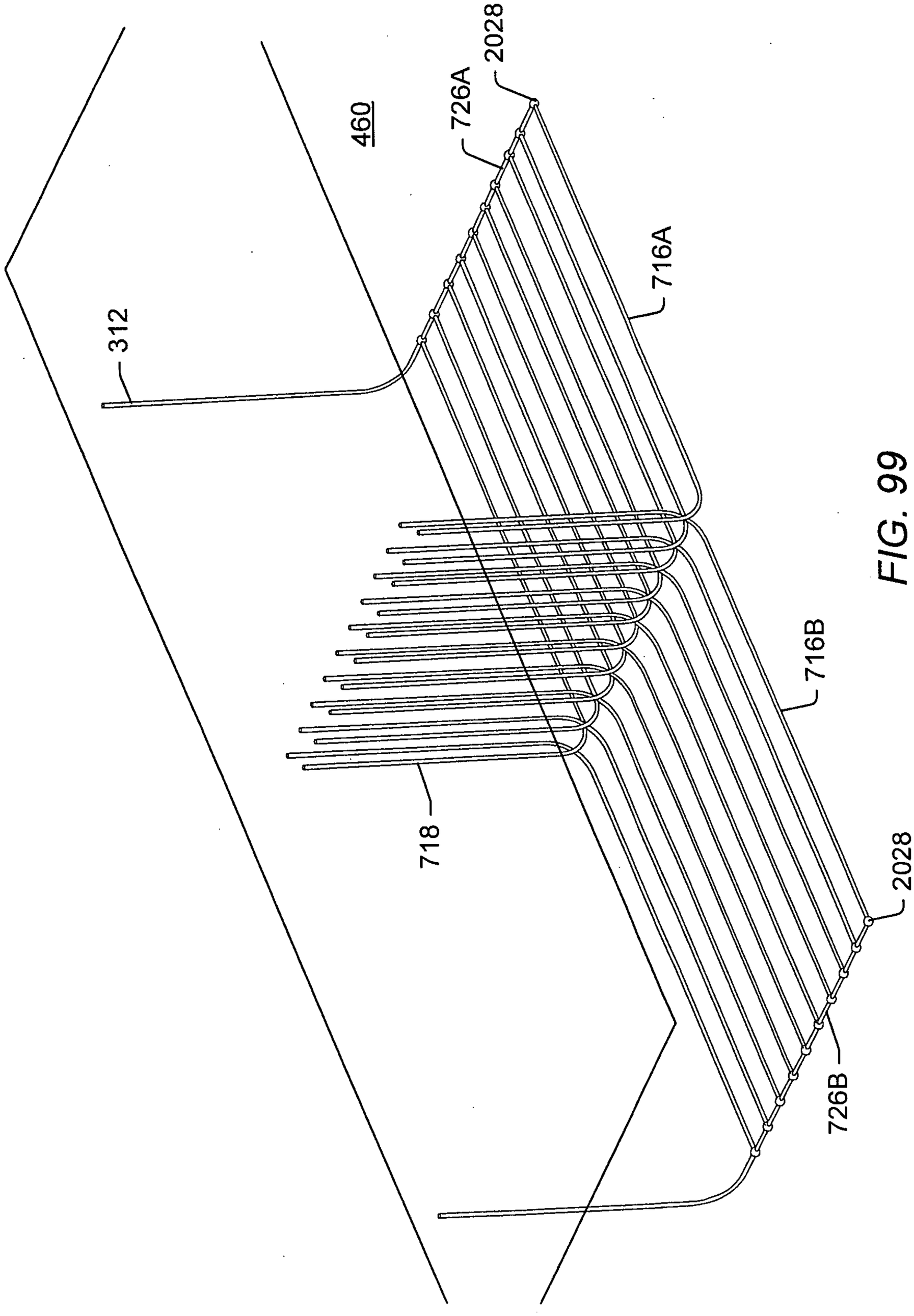


FIG. 99

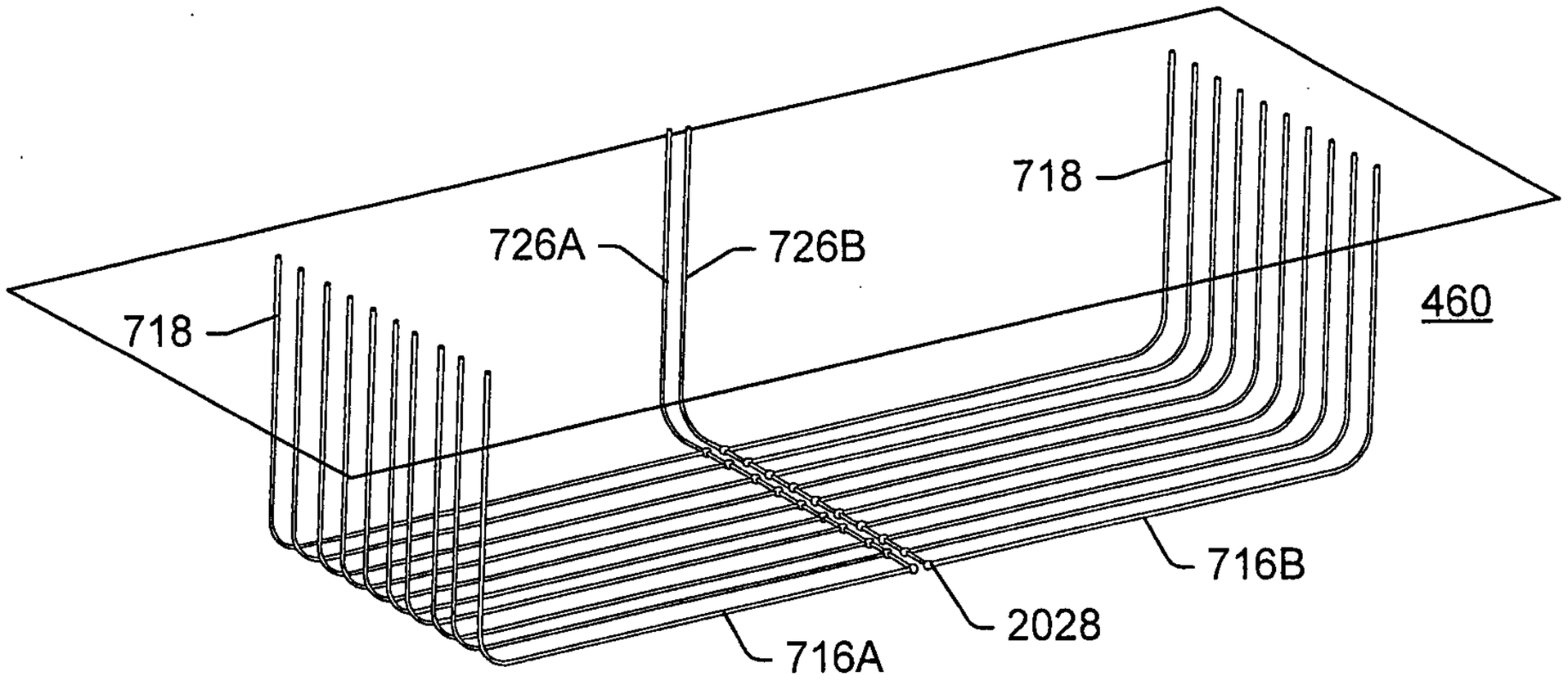


FIG. 100

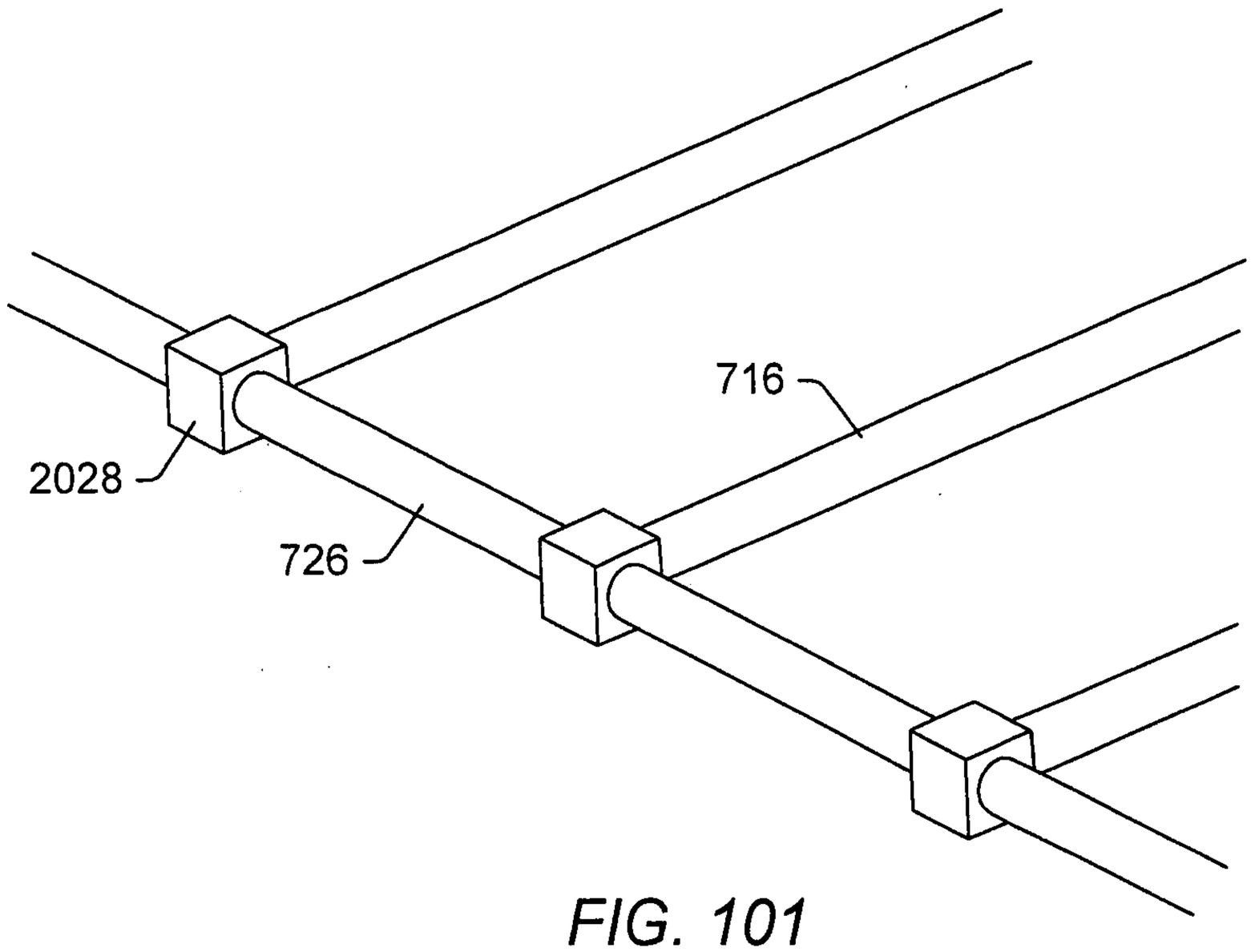


FIG. 101

FIG. 102

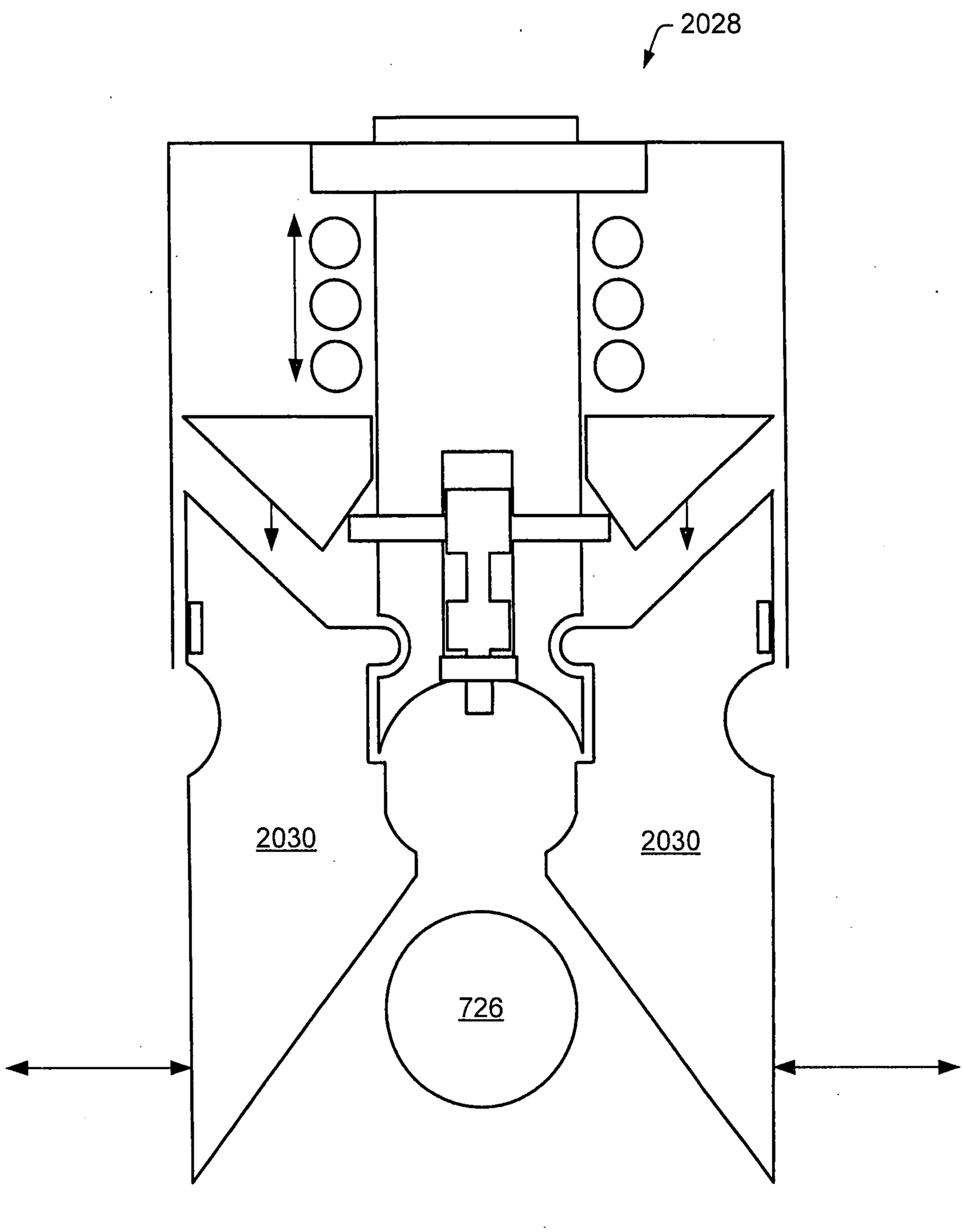


FIG. 103

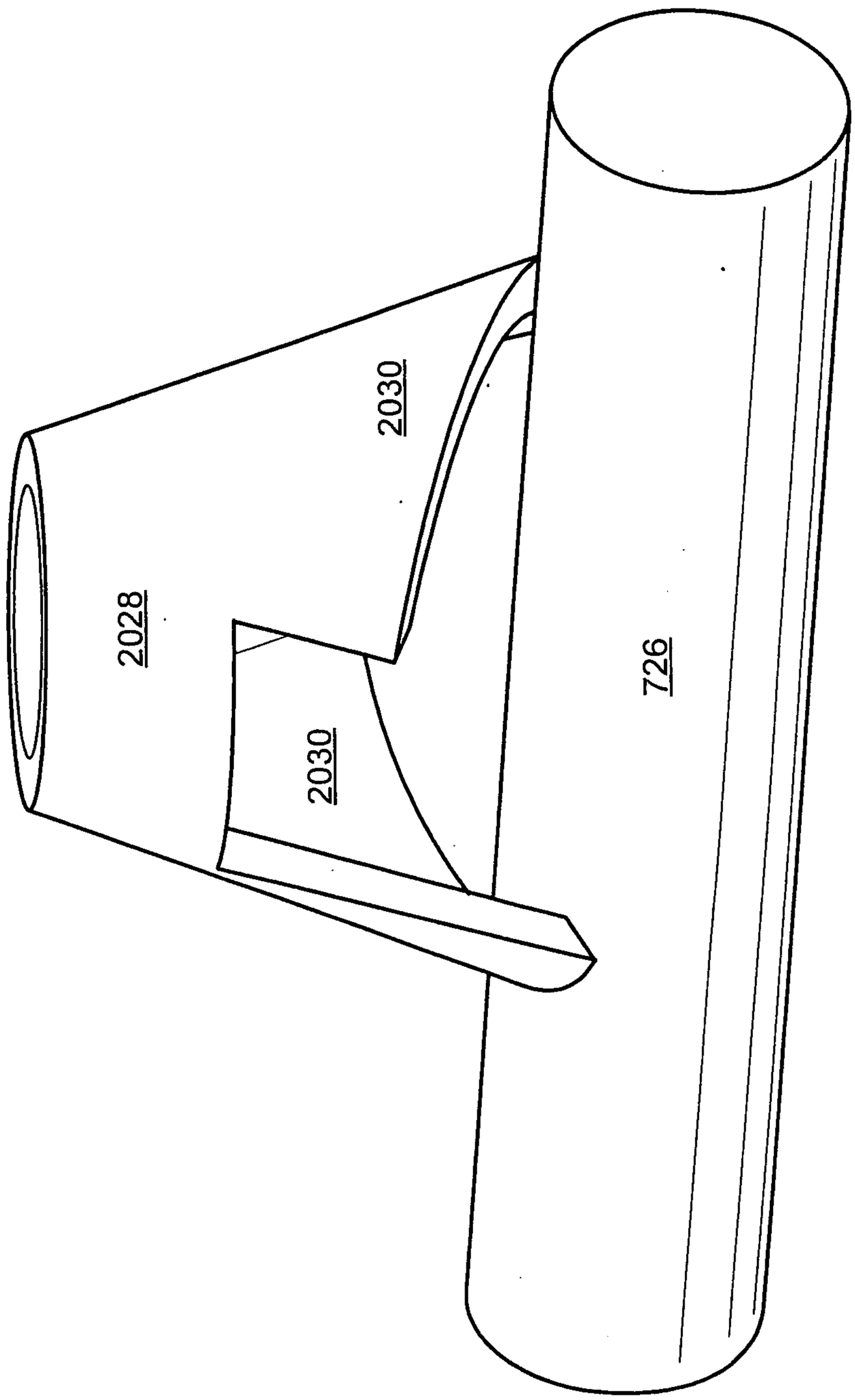


FIG. 104

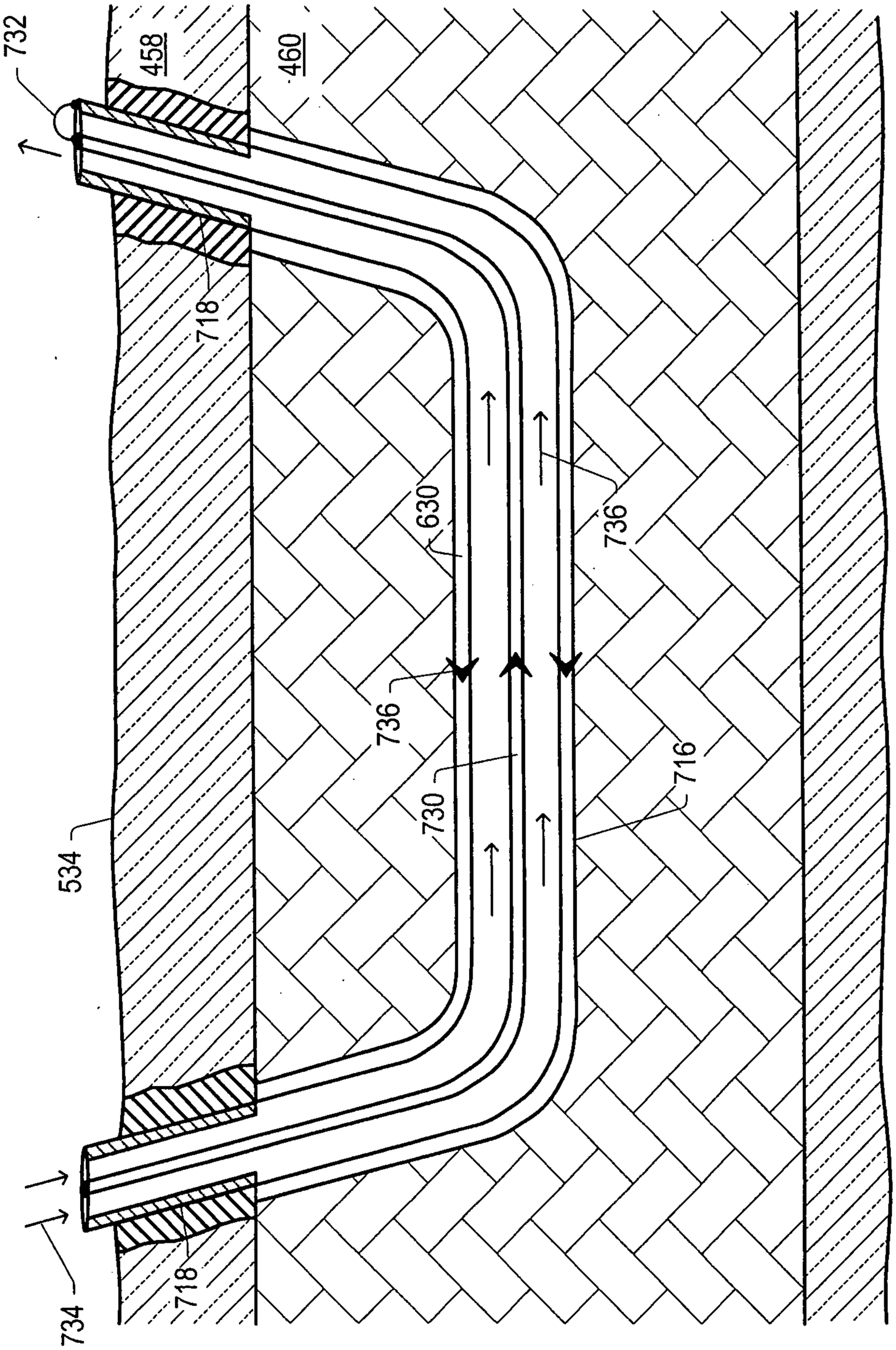


FIG. 105

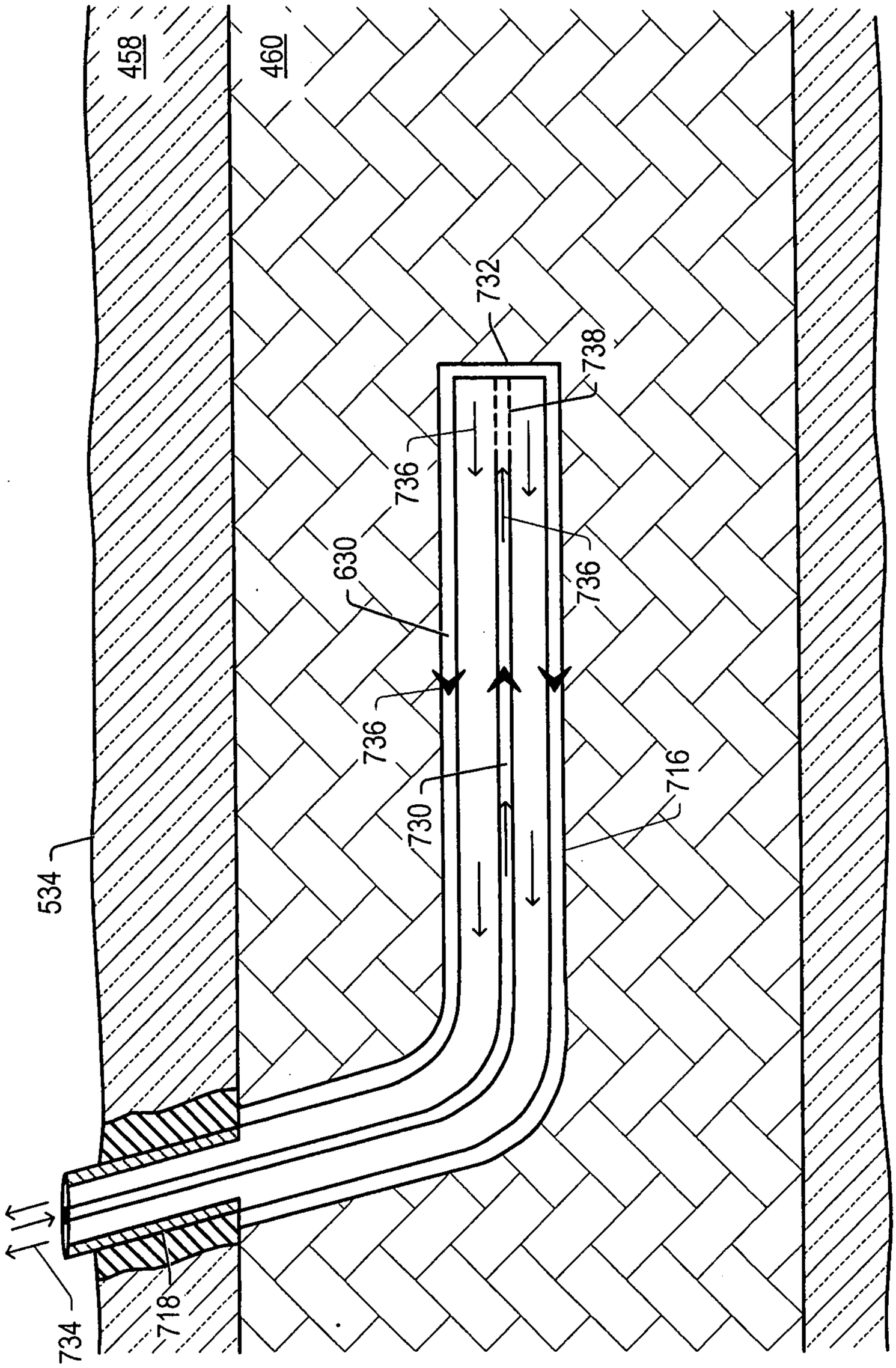


FIG. 106

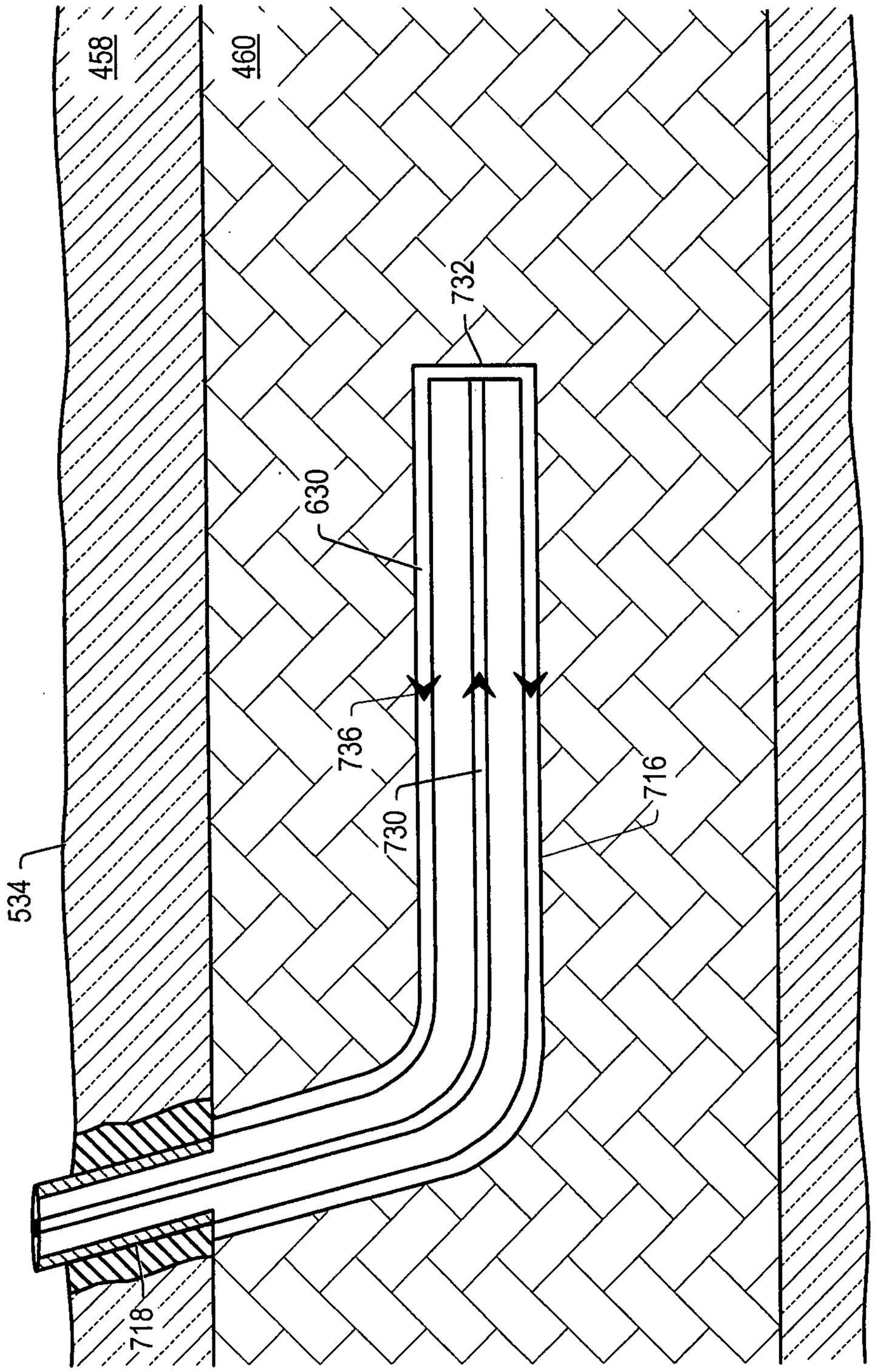


FIG. 107

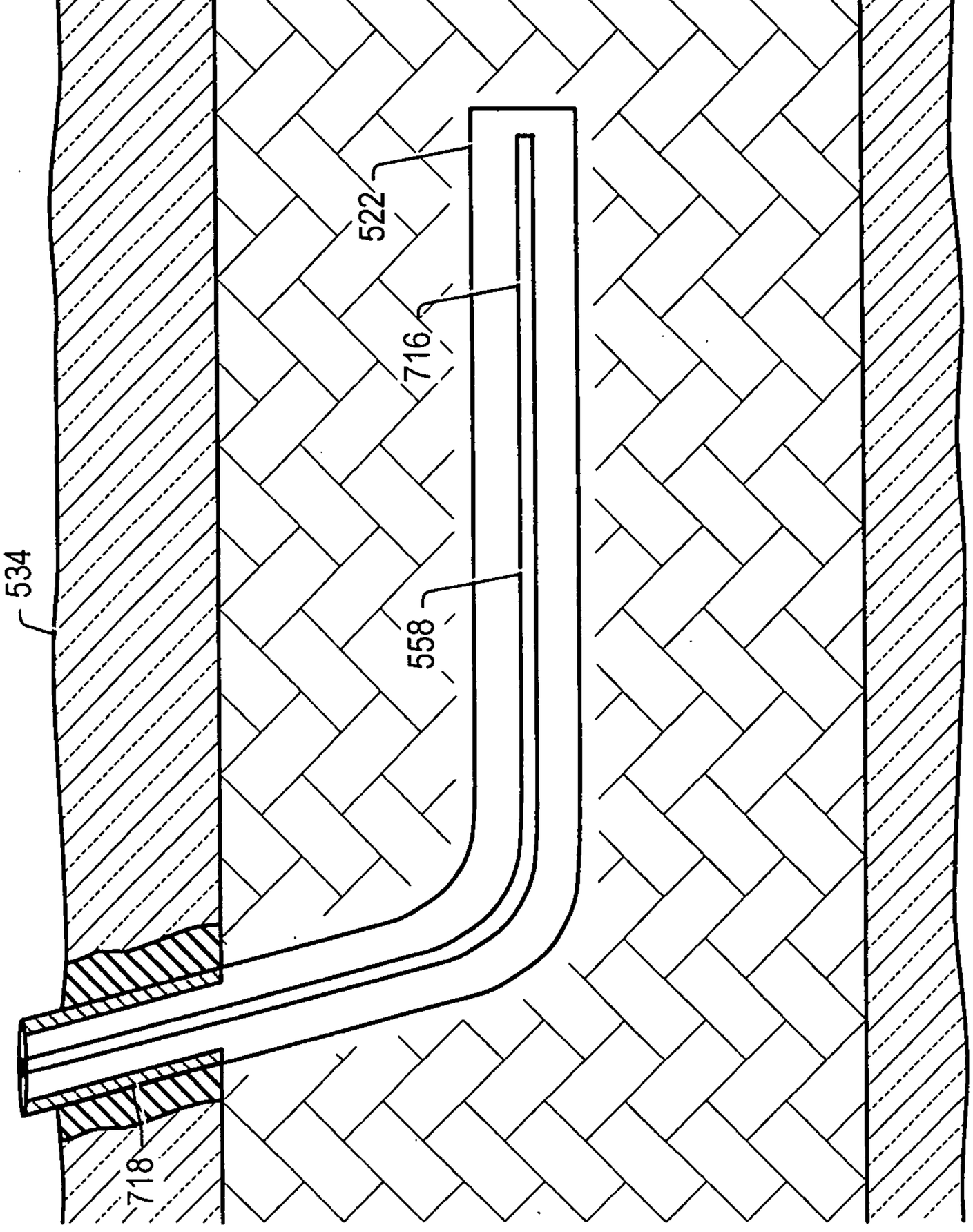


FIG. 109A

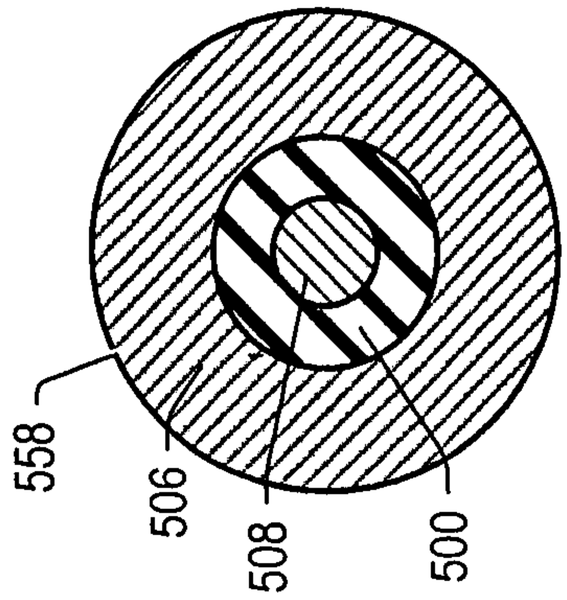
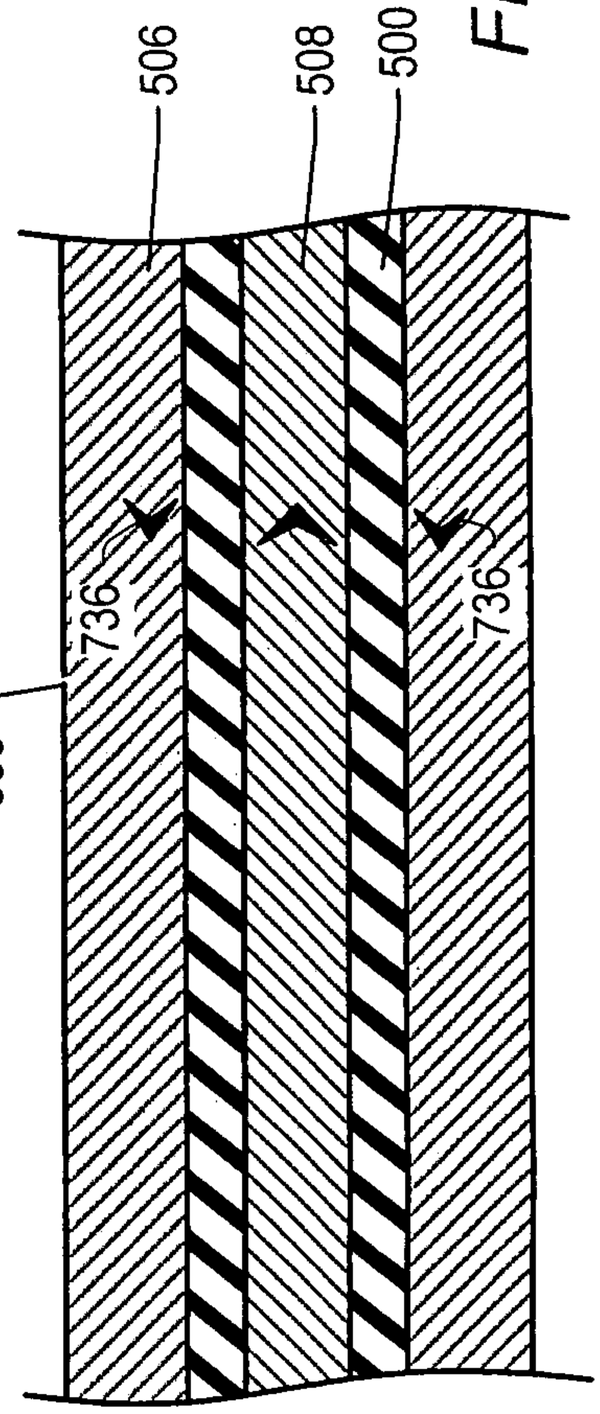


FIG. 109B



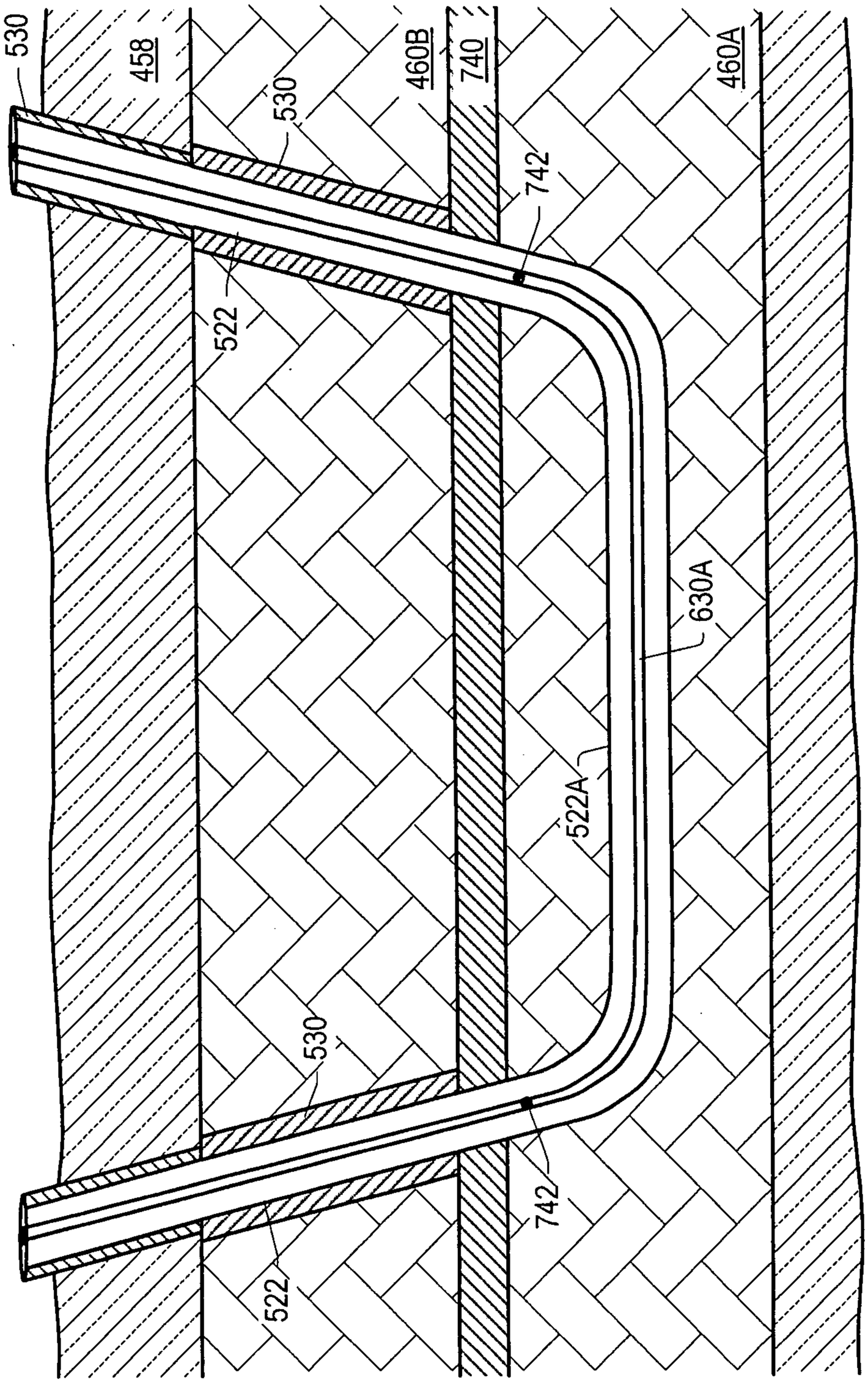


FIG. 110A

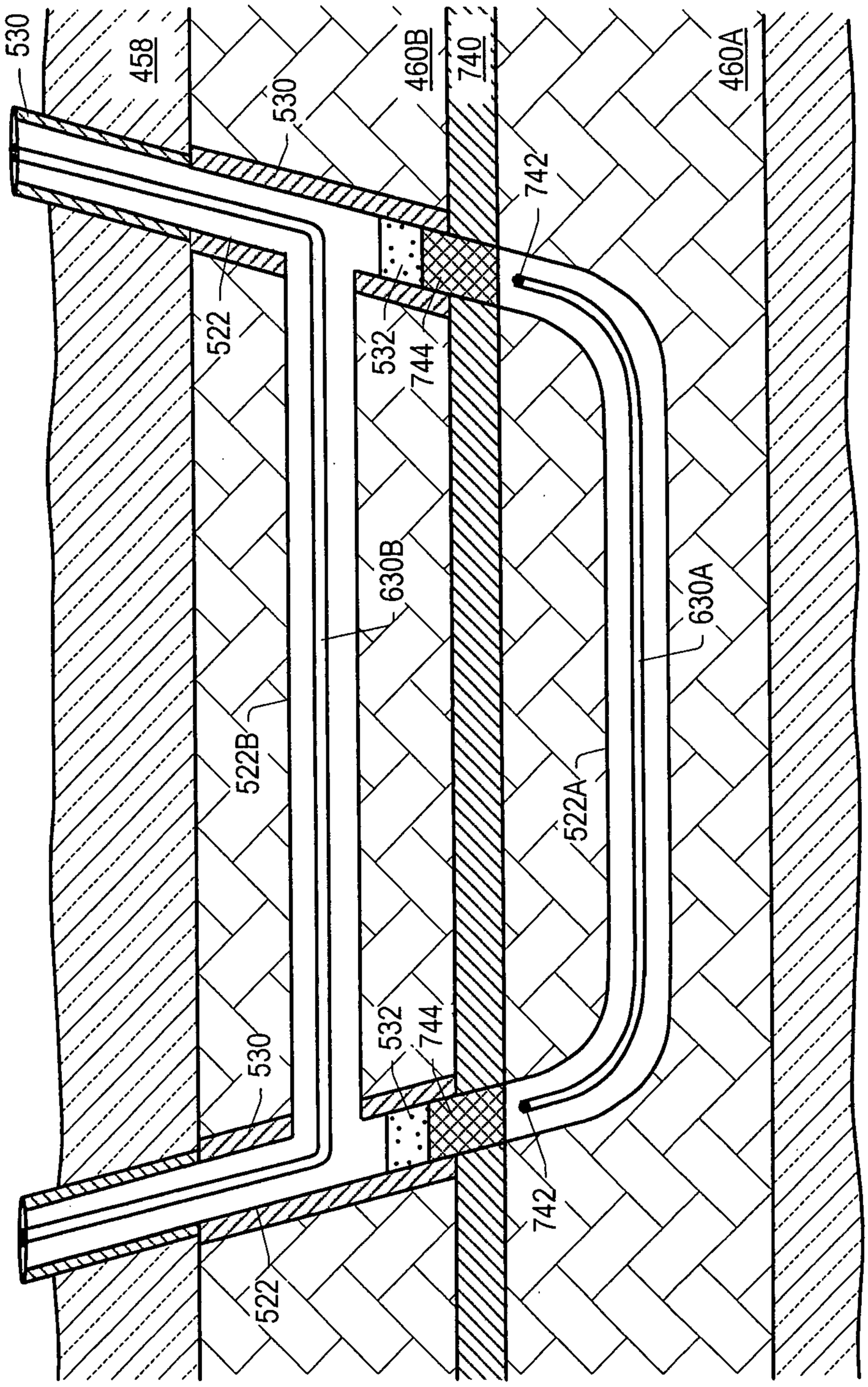

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FIG. 110B

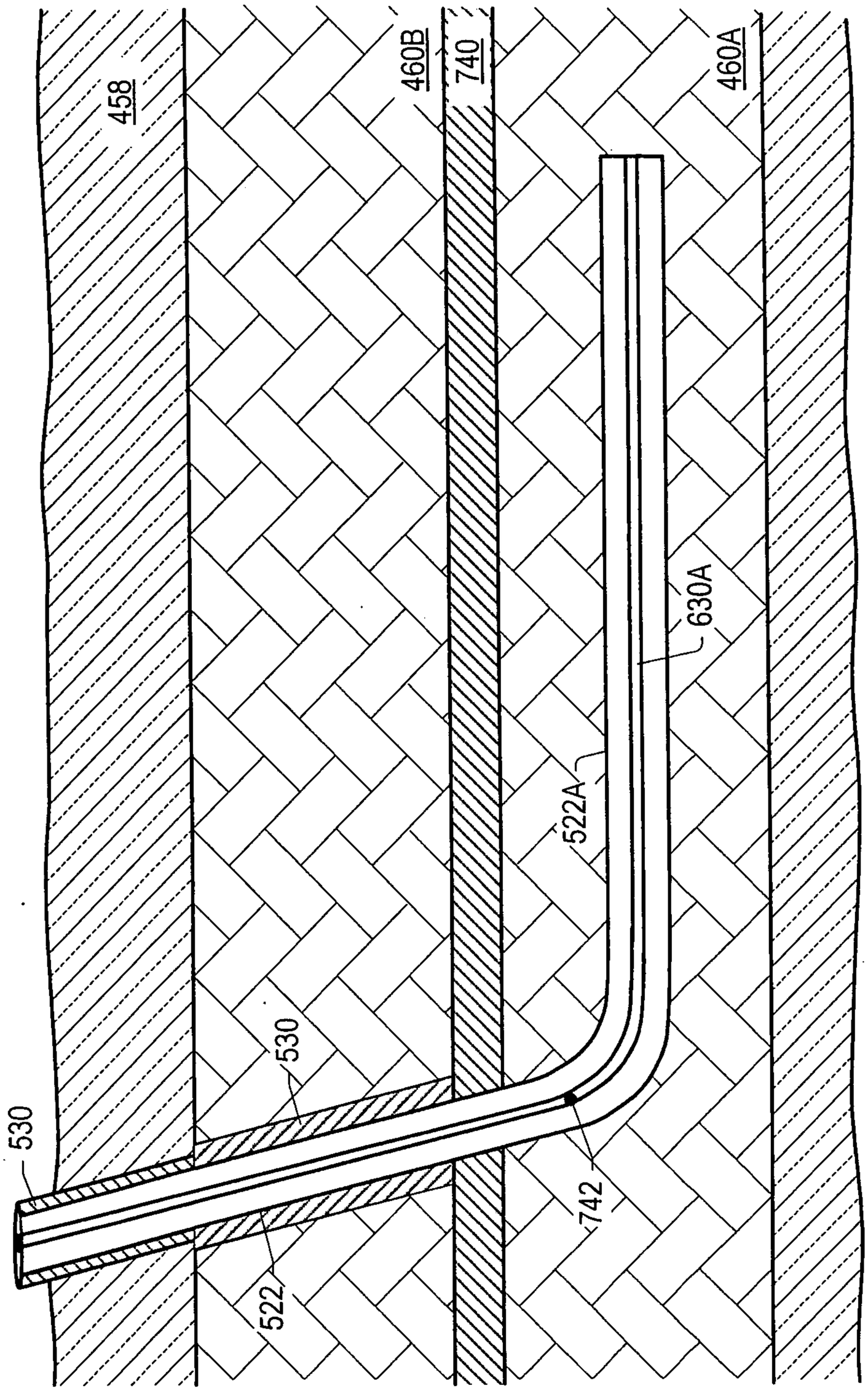


FIG. 111A

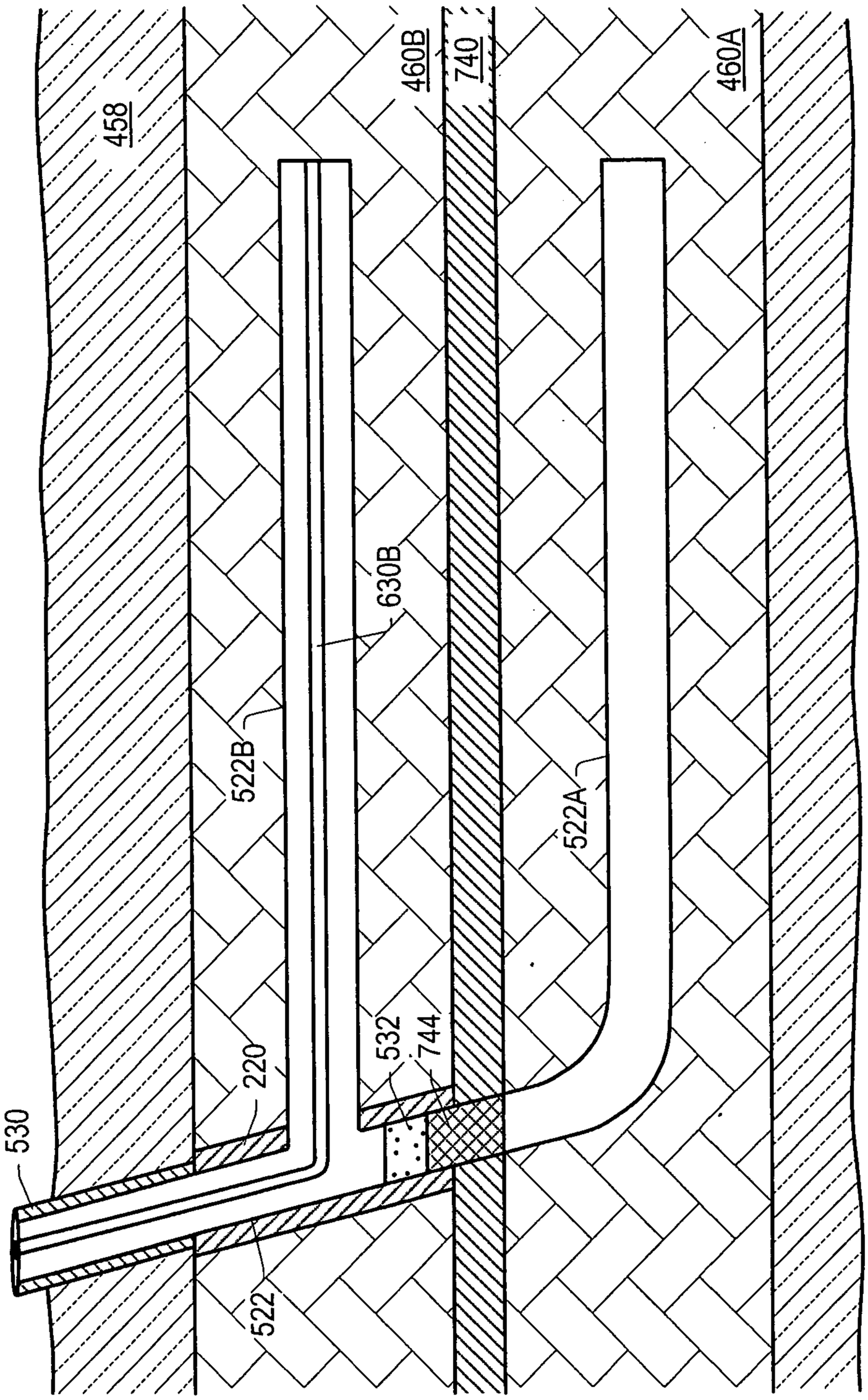


FIG. 111B

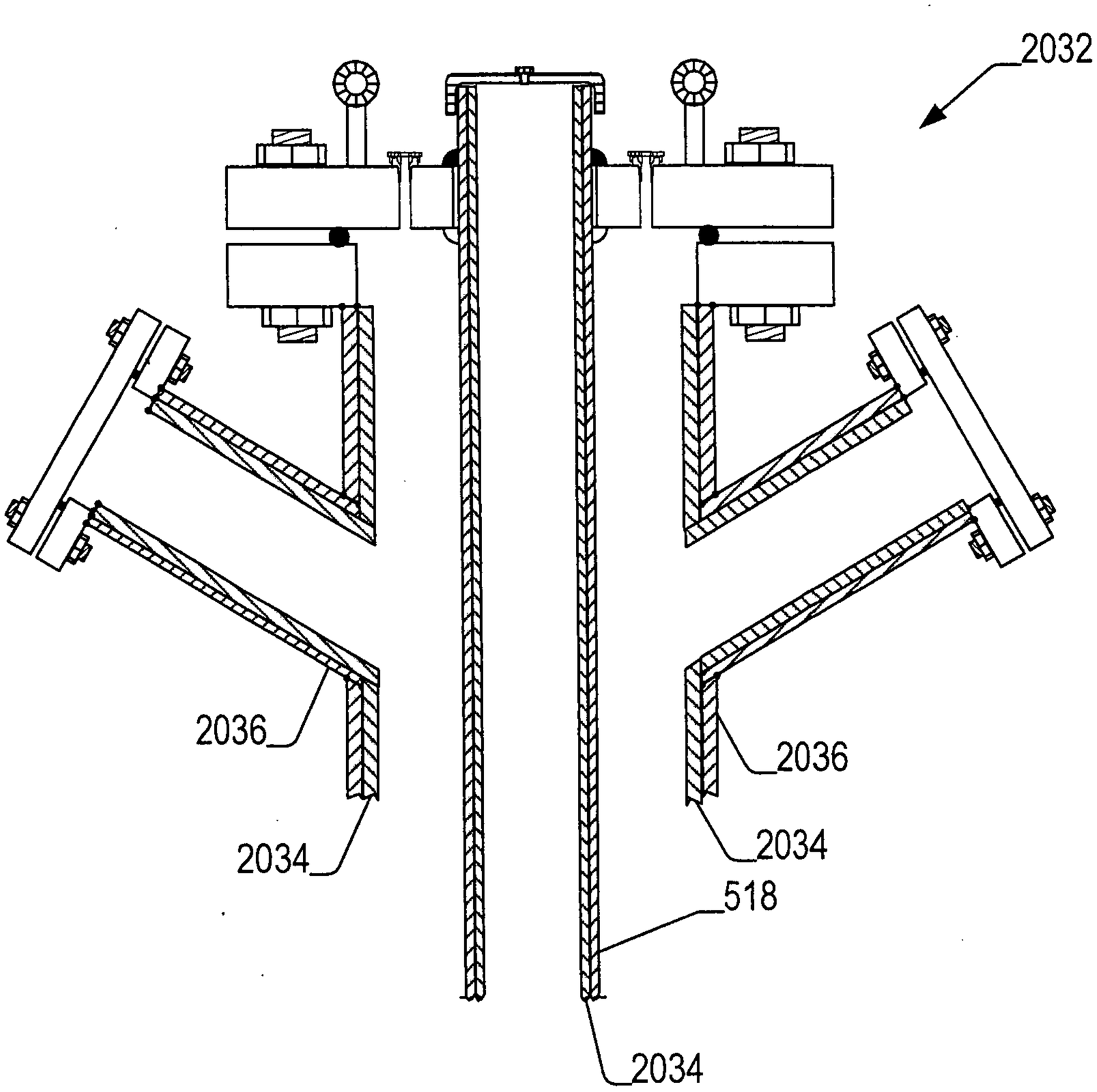


FIG. 112

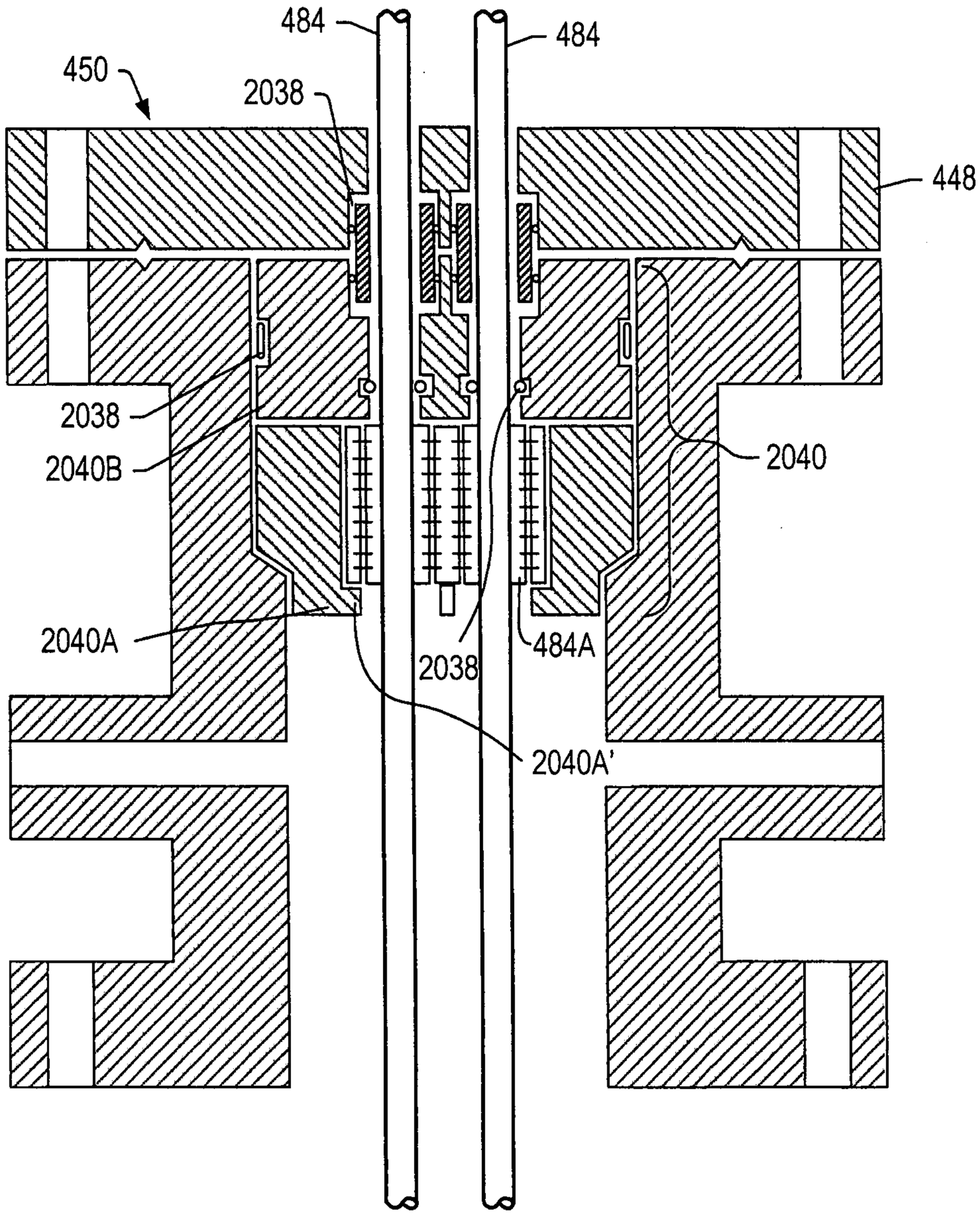


FIG. 113

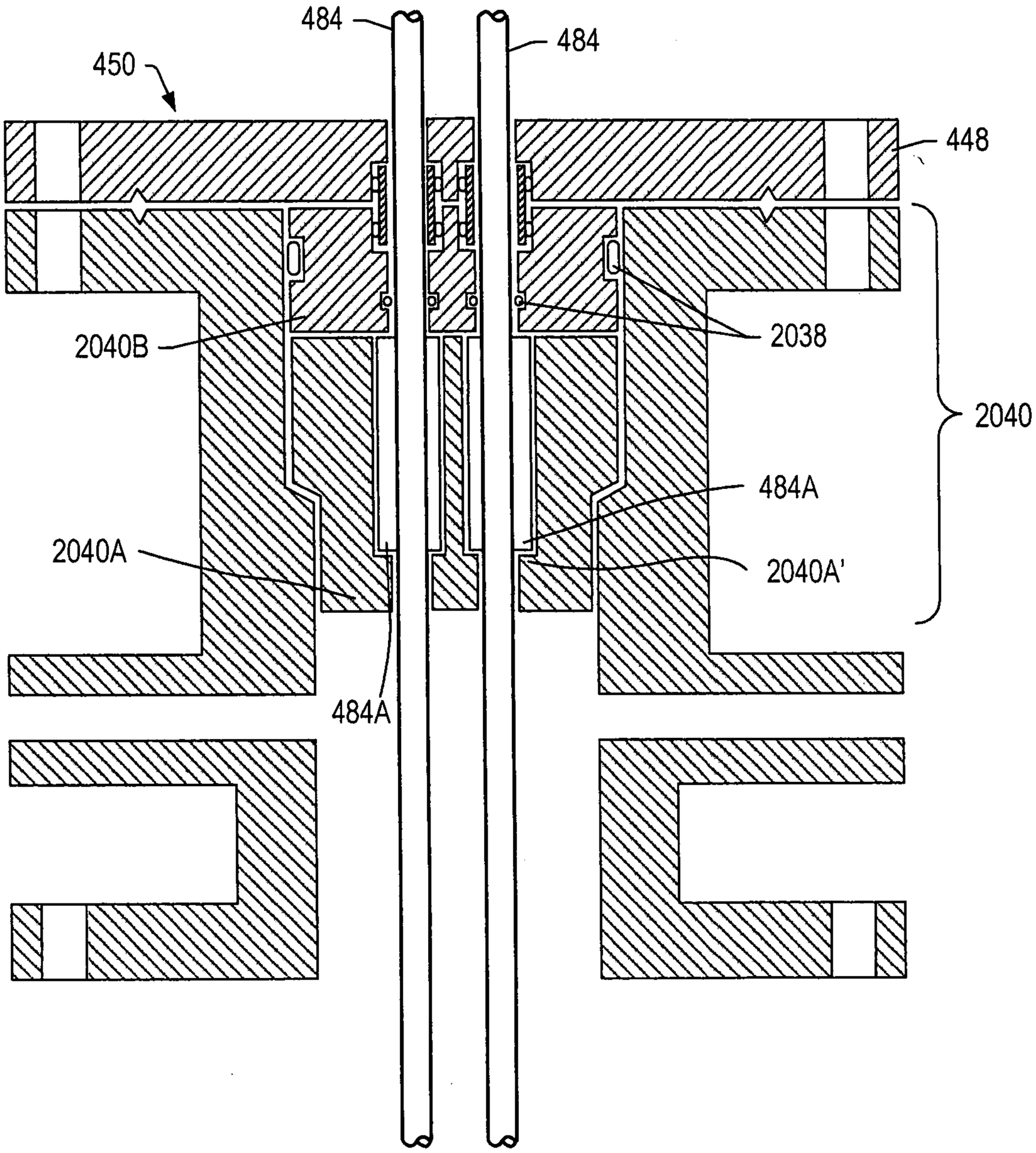


FIG. 114

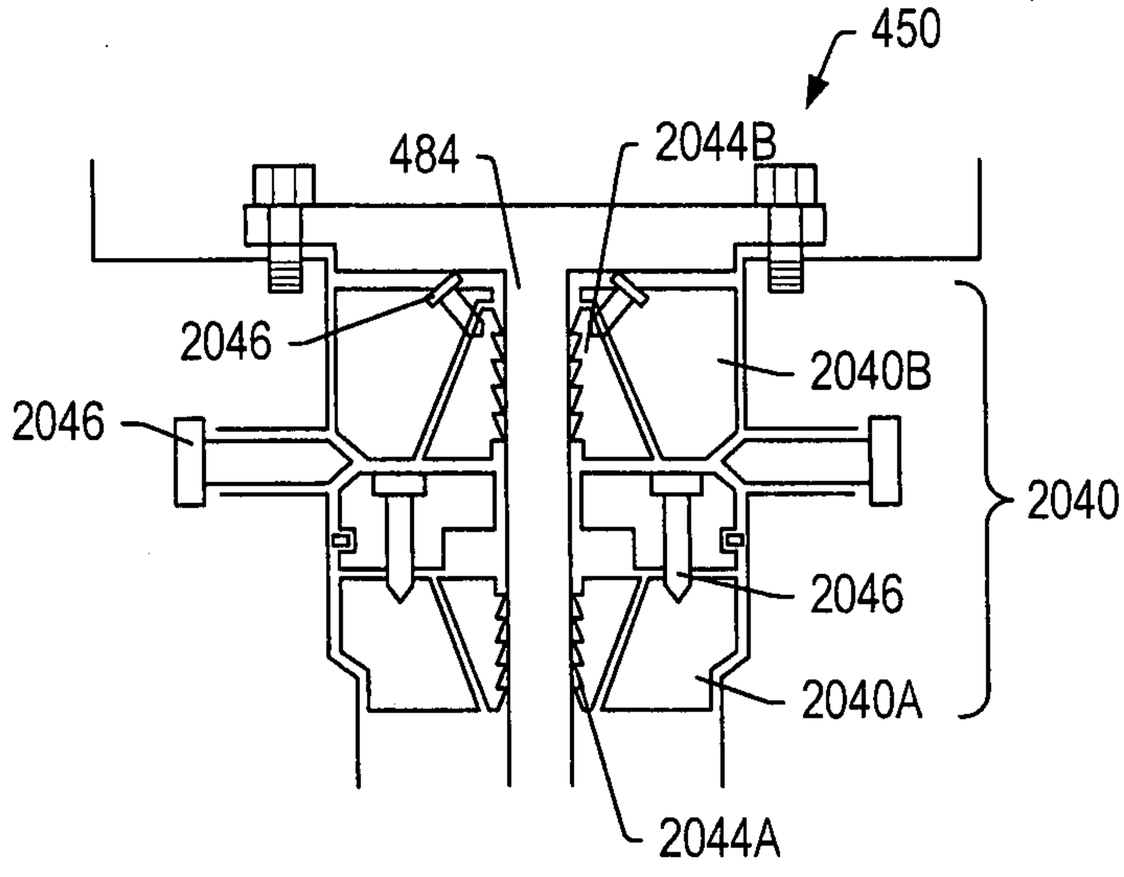


FIG. 115A

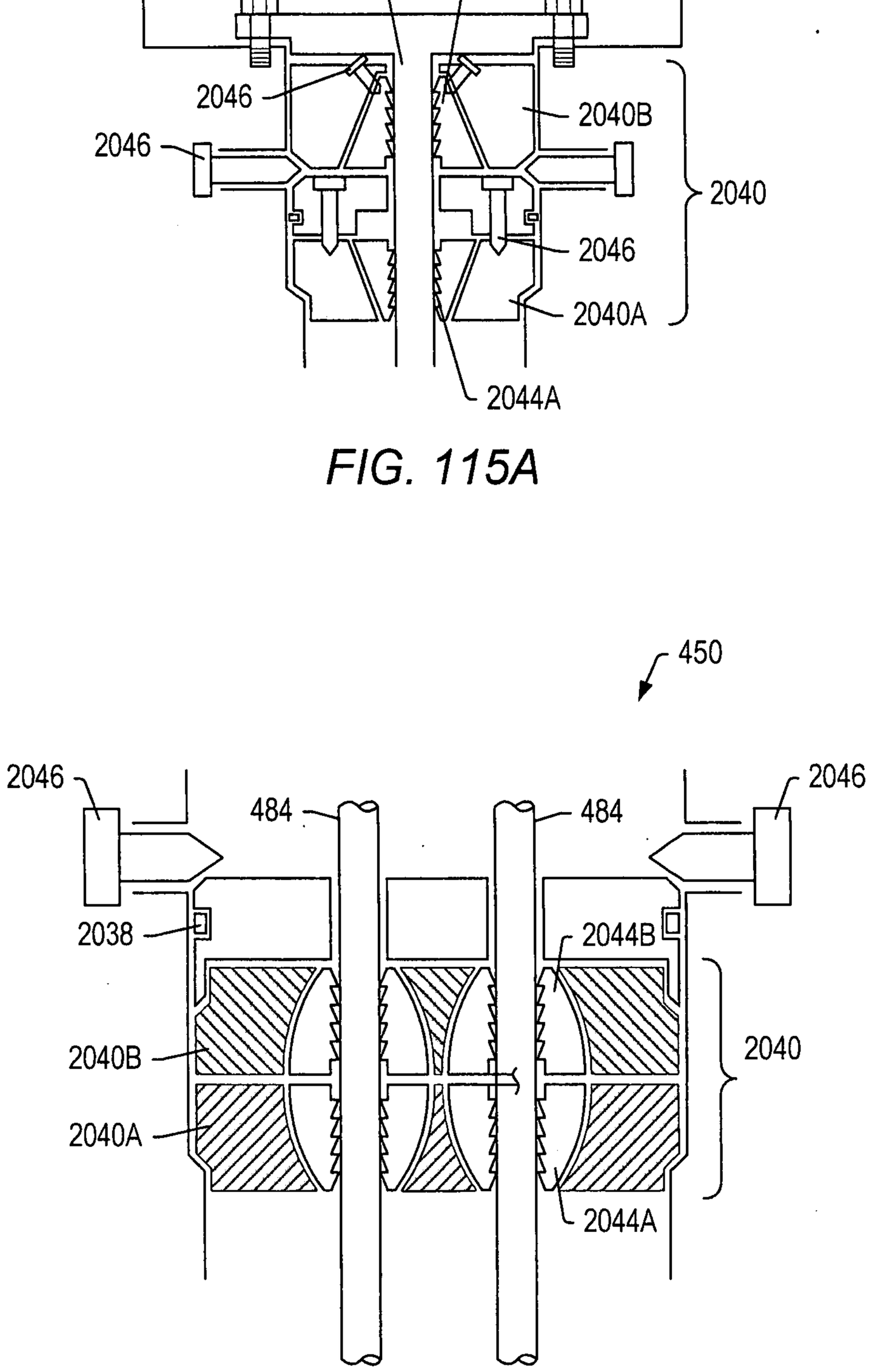


FIG. 115B

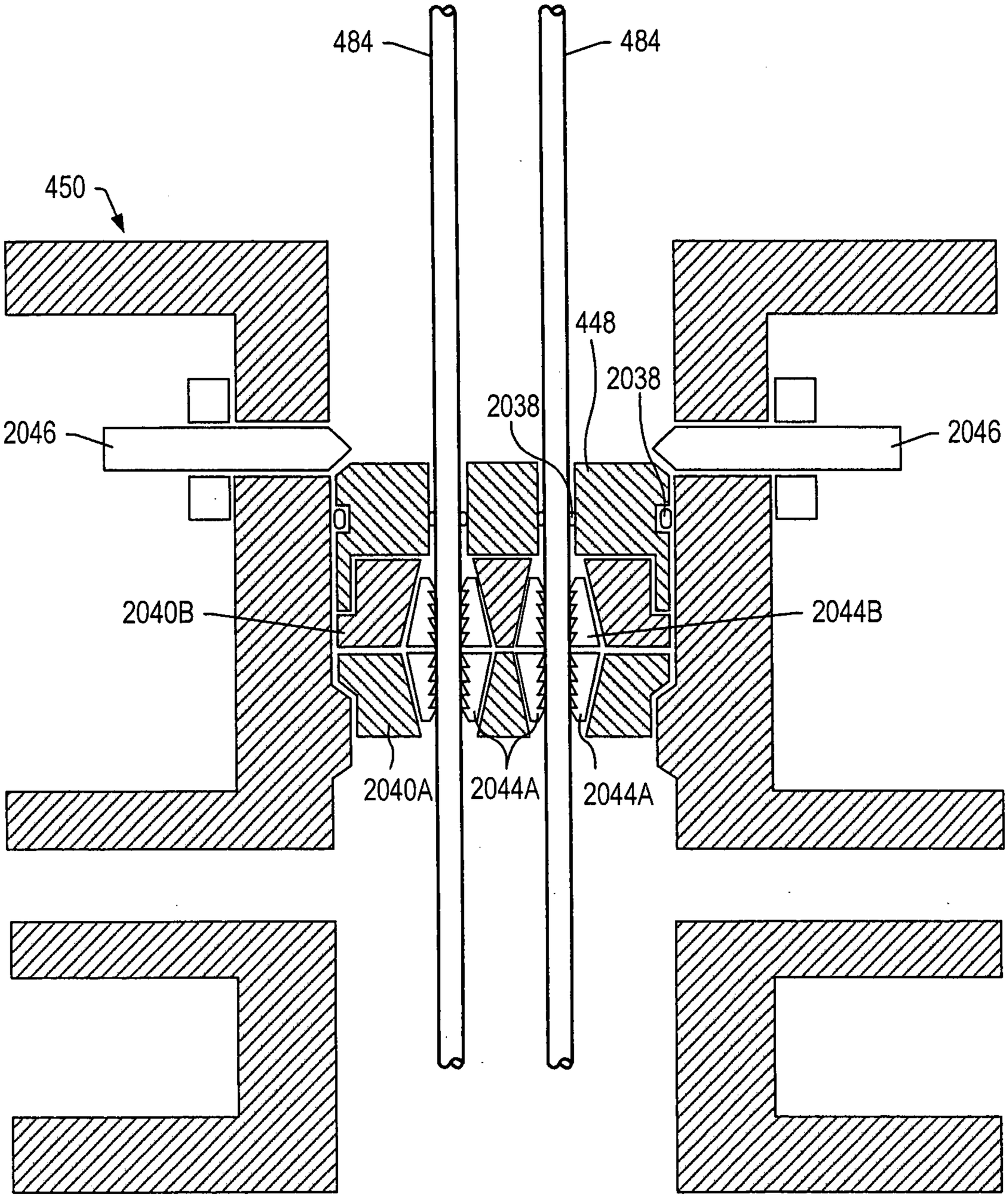

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FIG. 116

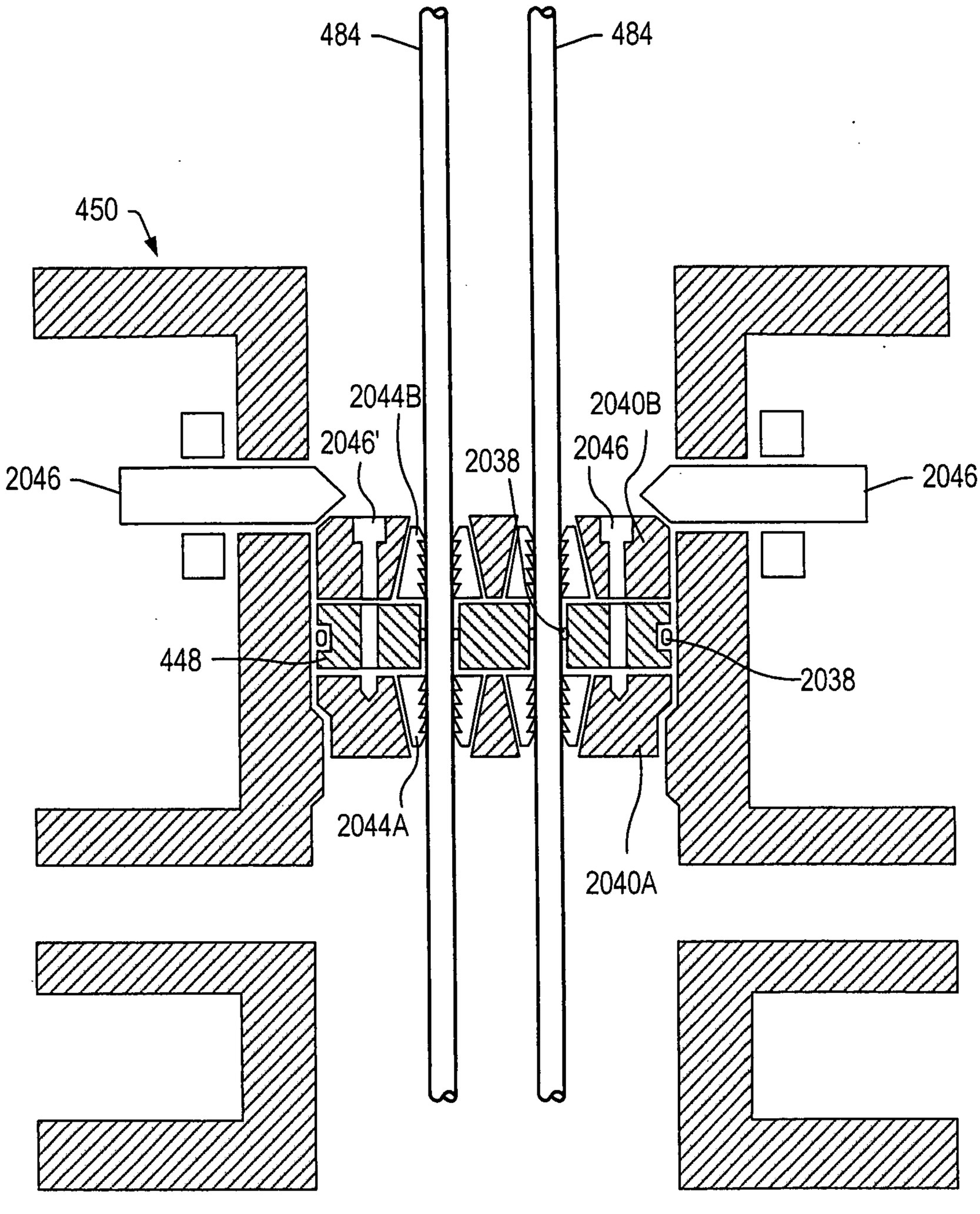

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2040A

FIG. 117

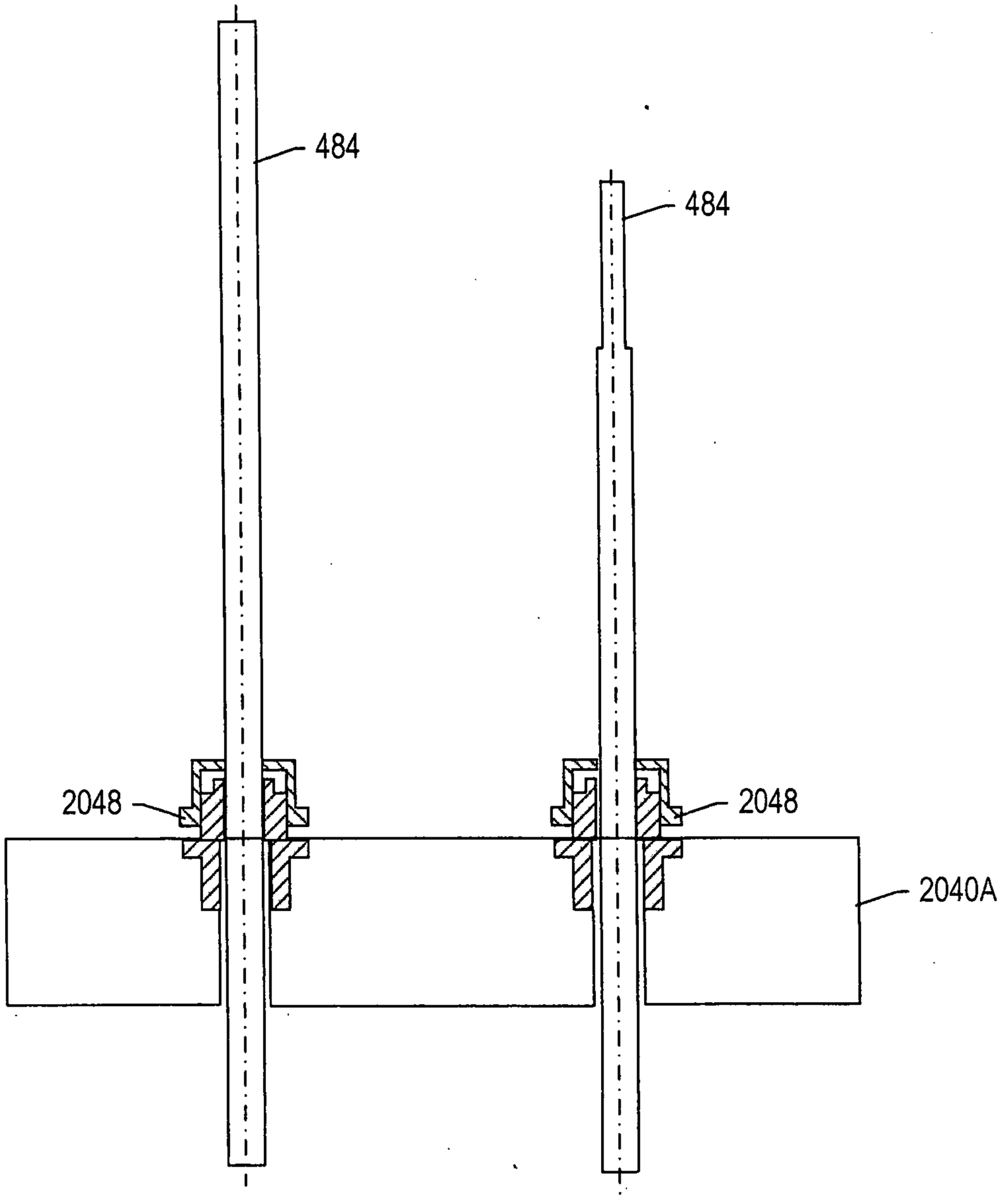


FIG. 118

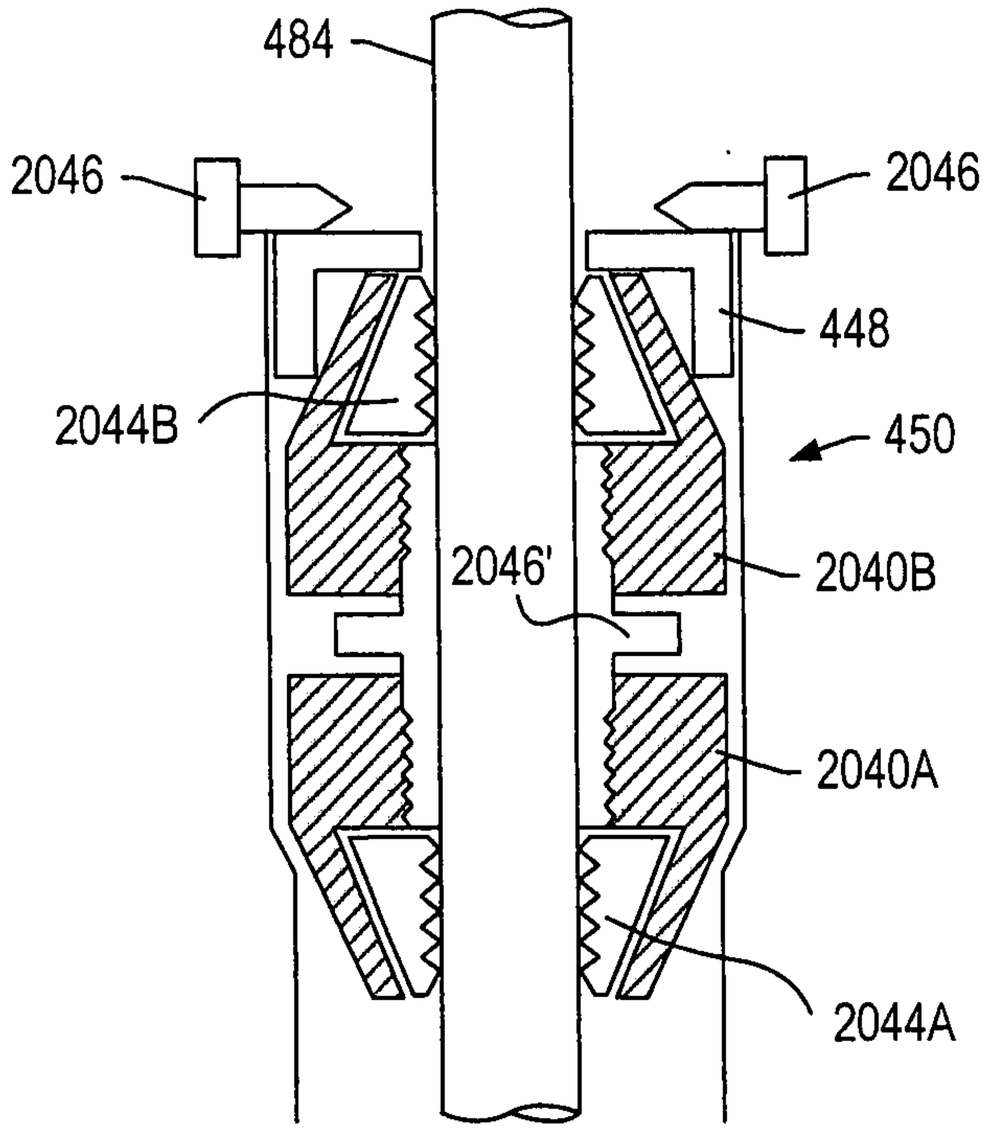


FIG. 119

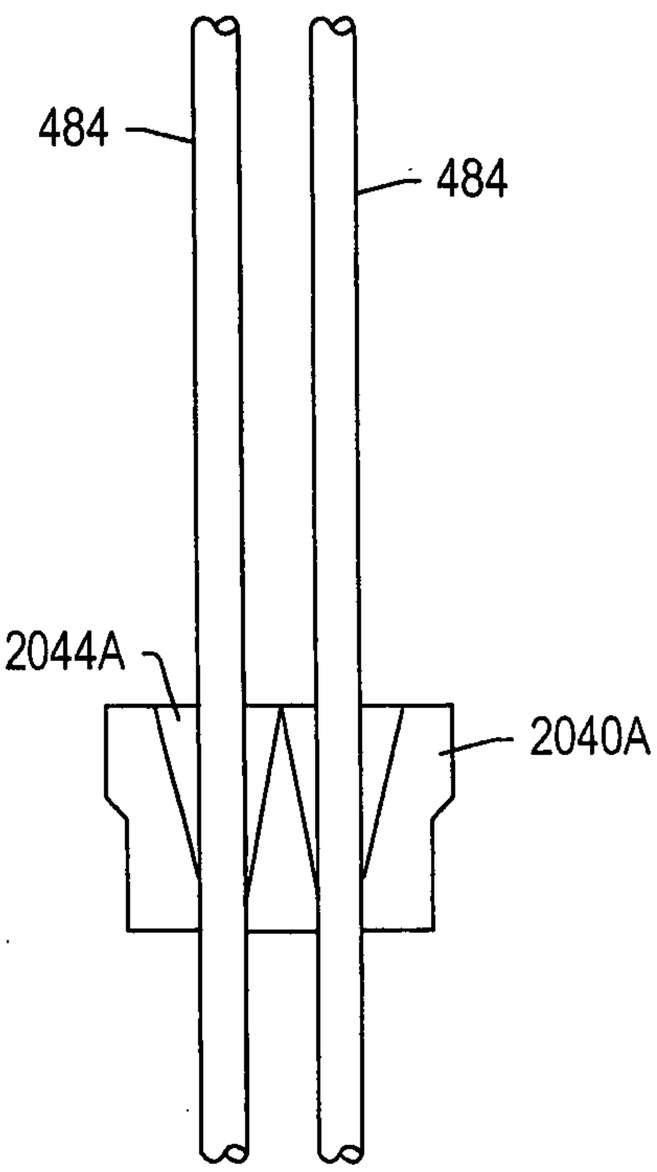


FIG. 120A

FIG. 120B

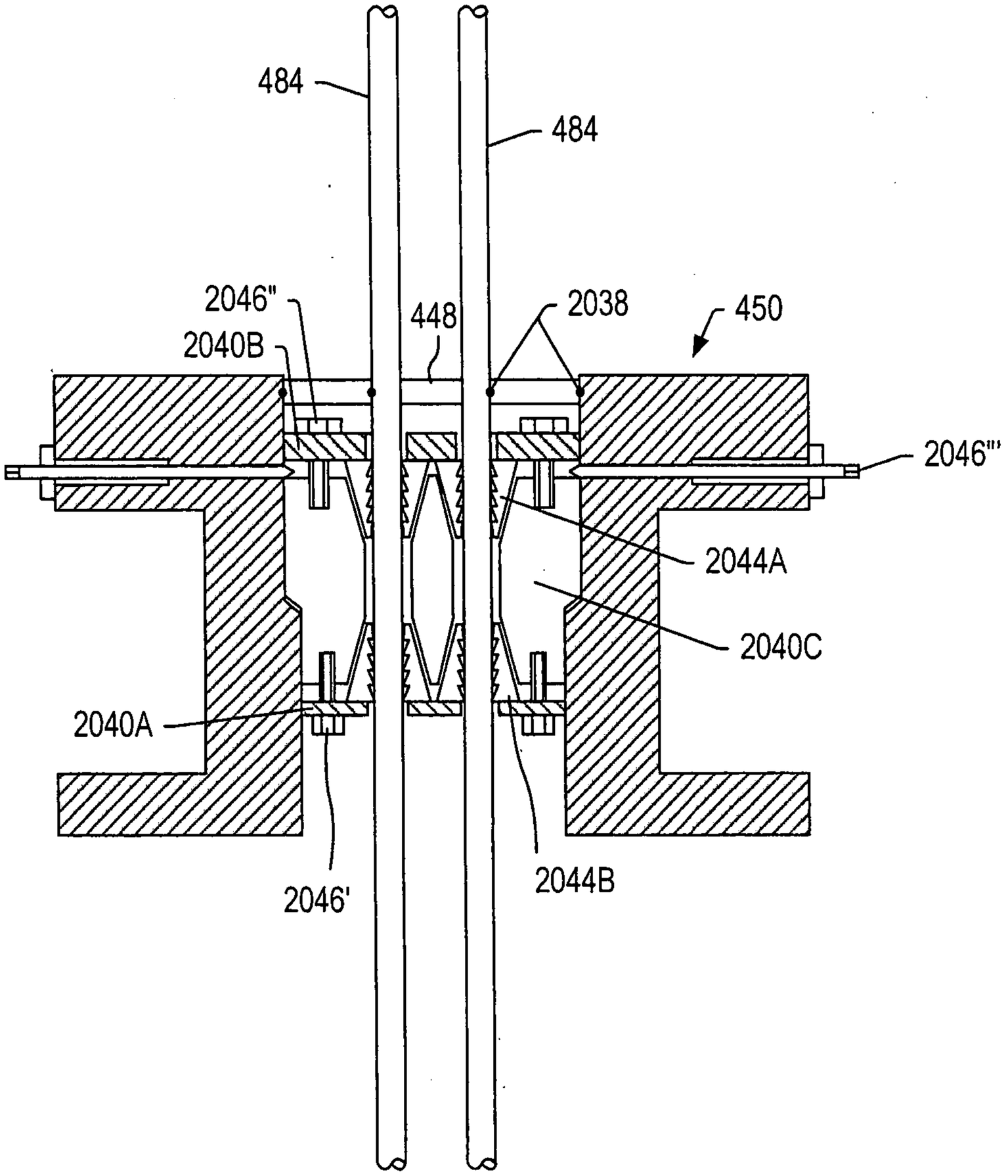

484
484
2046"
2040B
448
2038
450
2046"'
2044A
2040C
2040A
2046'
2044B

FIG. 121

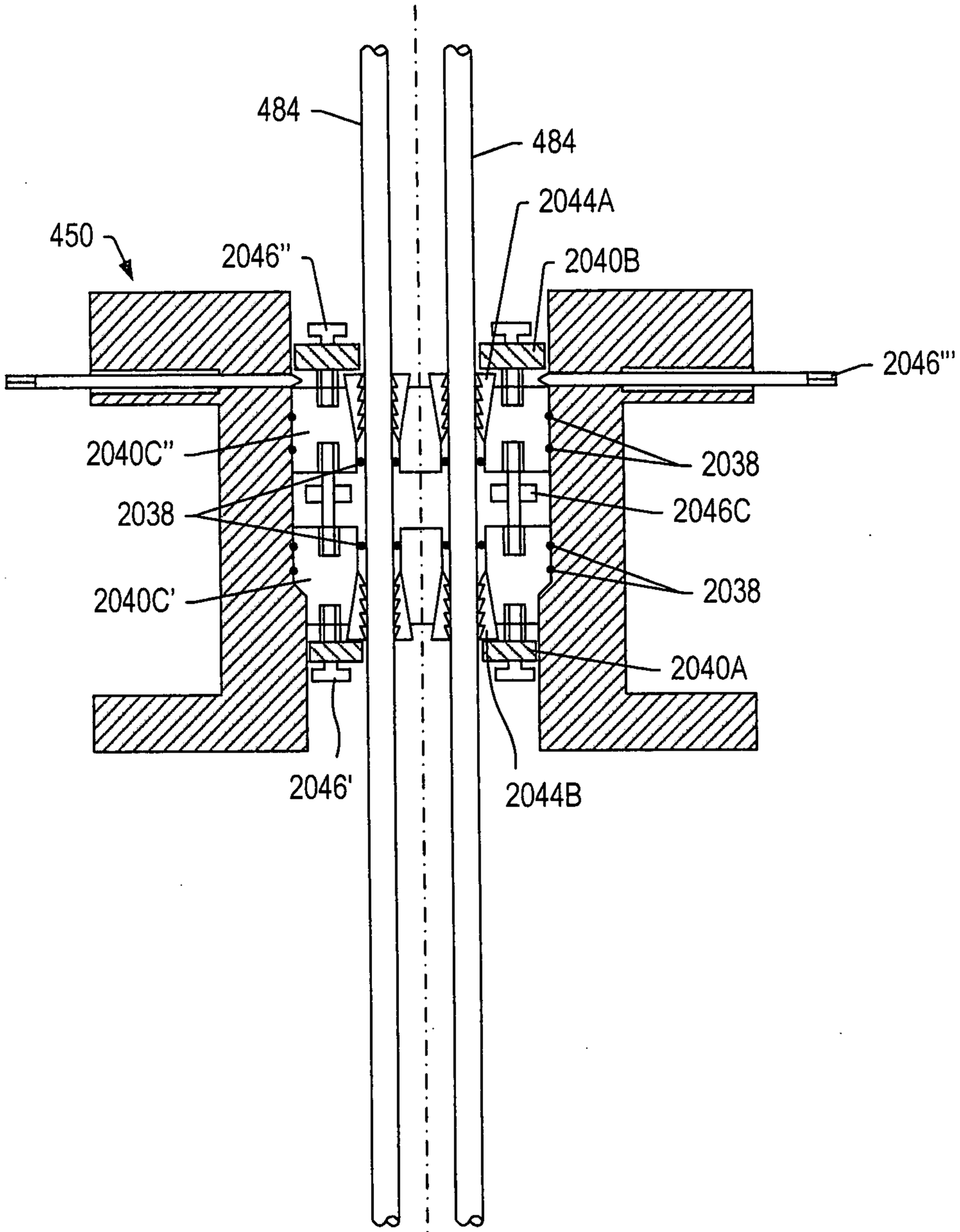

484
484
2044A
450
2046"
2040B
2046'''
2040C"
2038
2038
2046C
2040C'
2038
2040A
2046'
2044B

FIG. 122

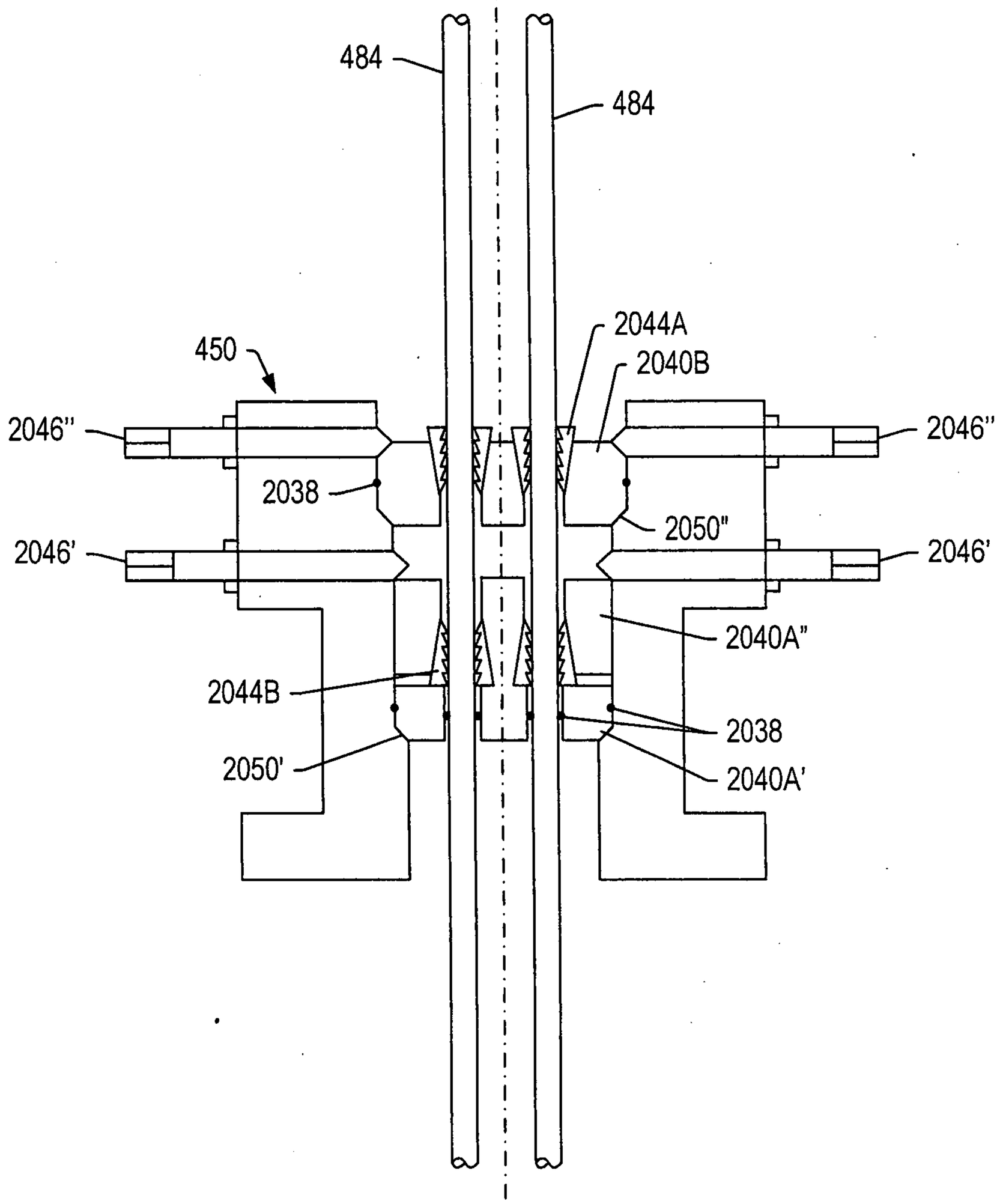

484
484
450
2044A
2040B
2046"
2046"
2038
2050"
2046'
2046'
2040A"
2044B
2038
2050'
2040A'

FIG. 123

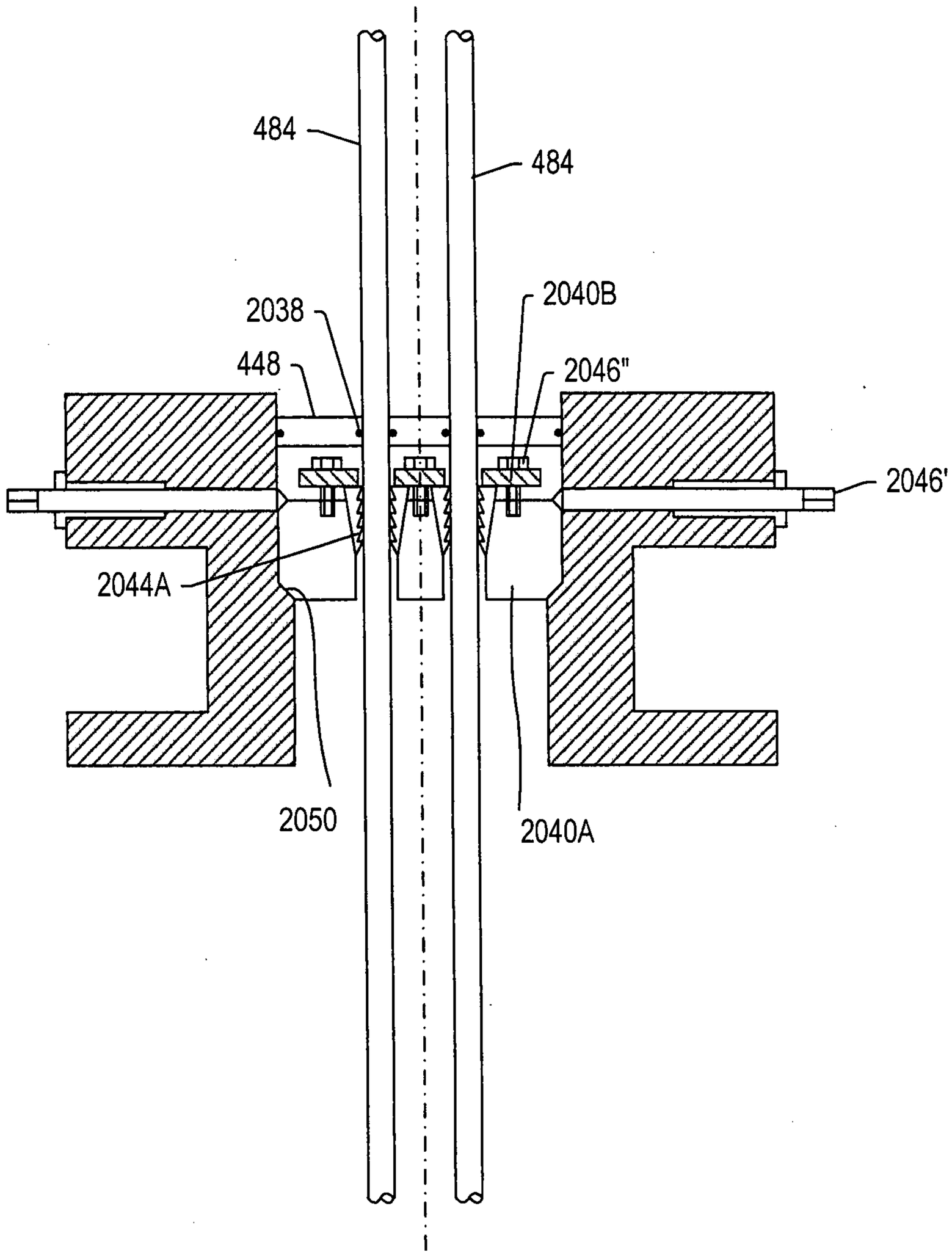


FIG. 124

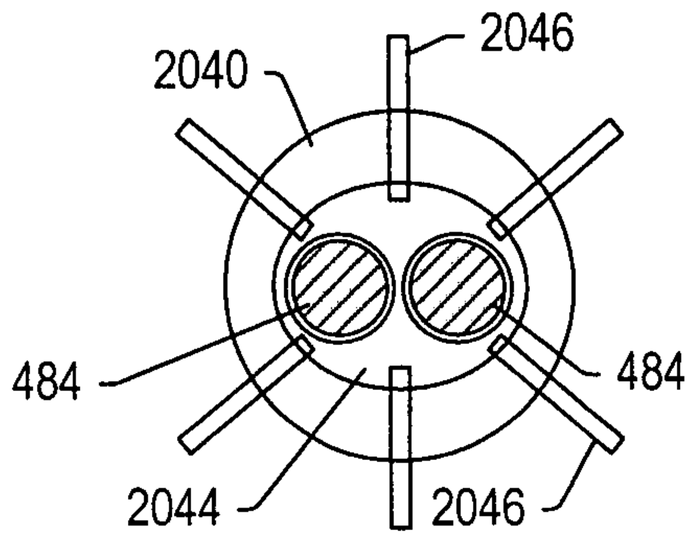


FIG. 125

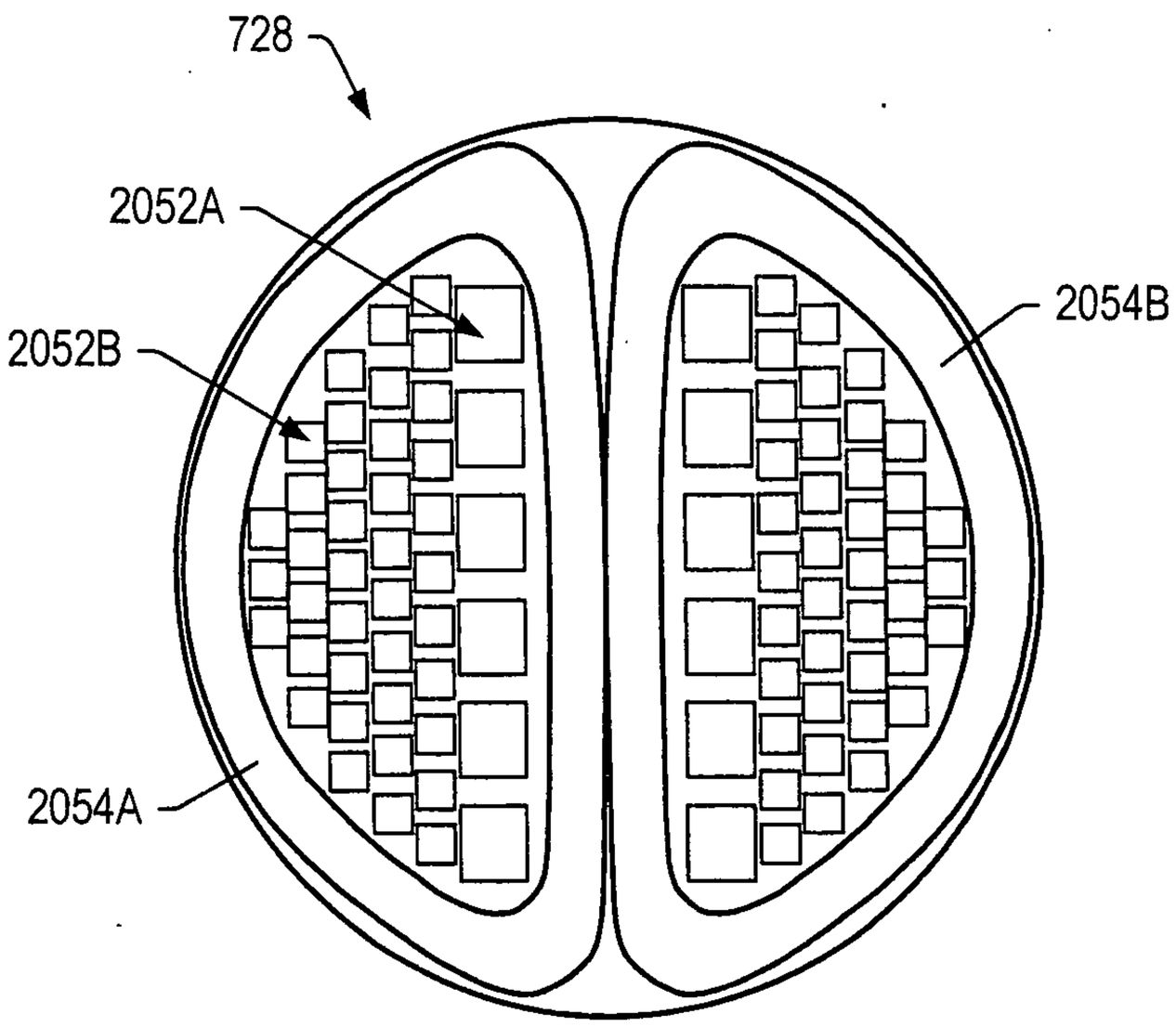


FIG. 126

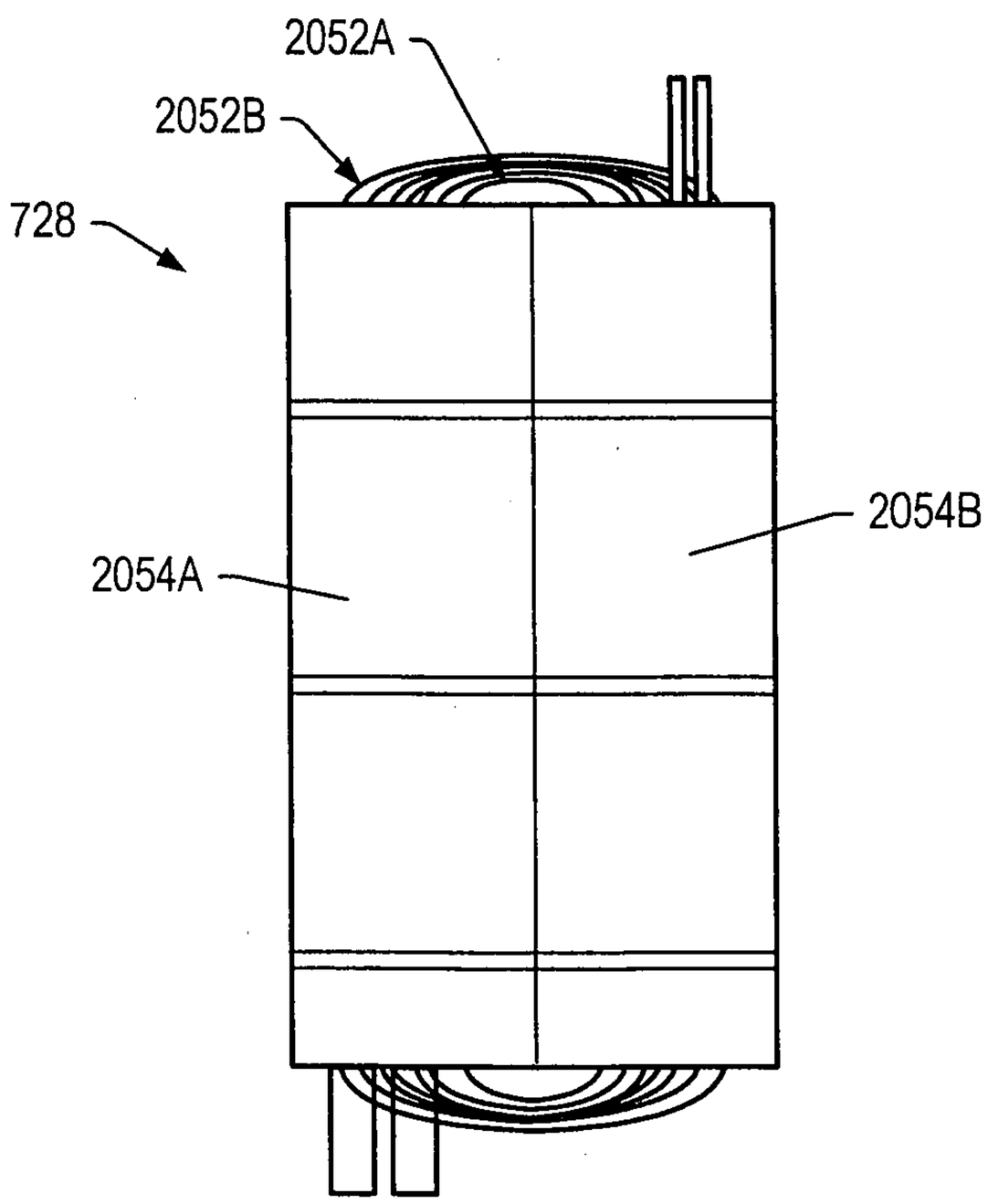


FIG. 127

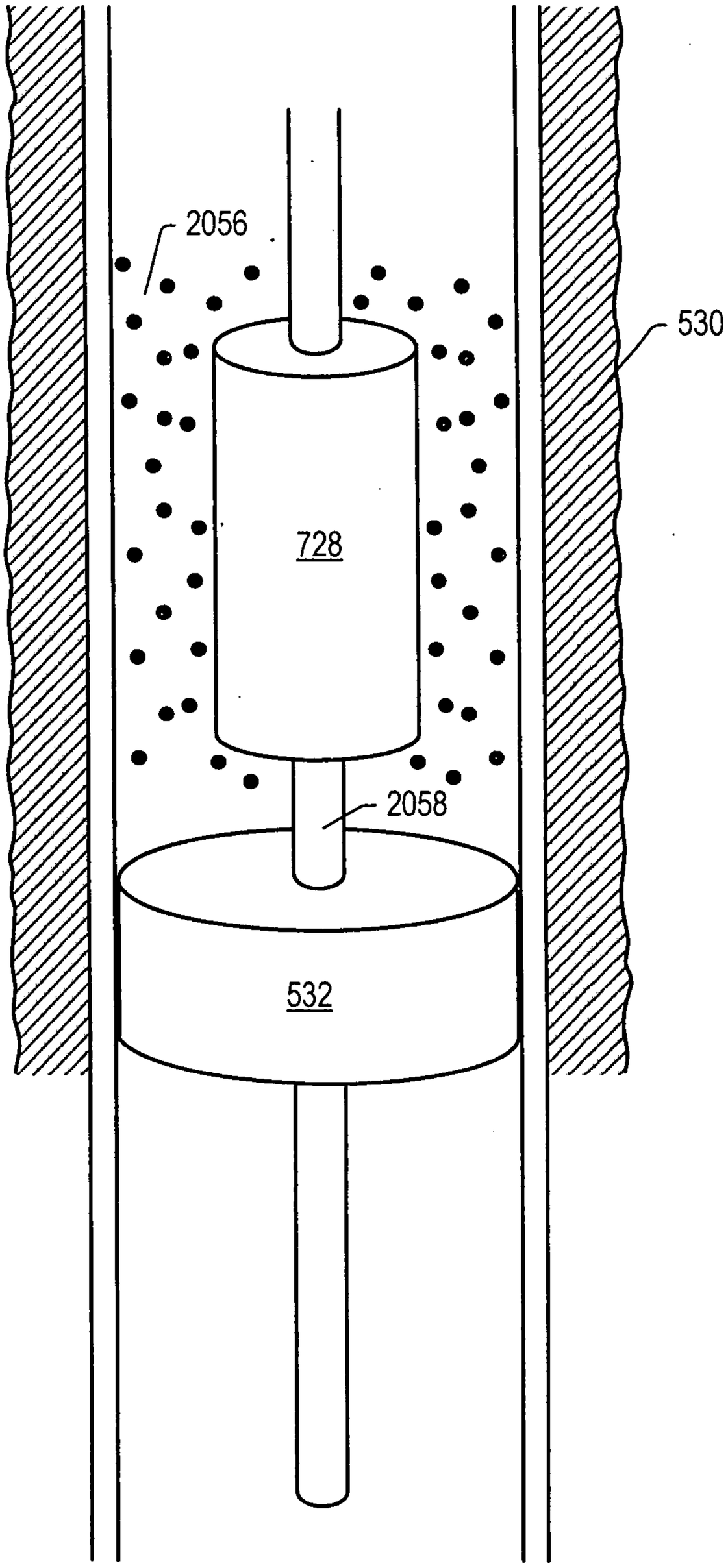


FIG. 128

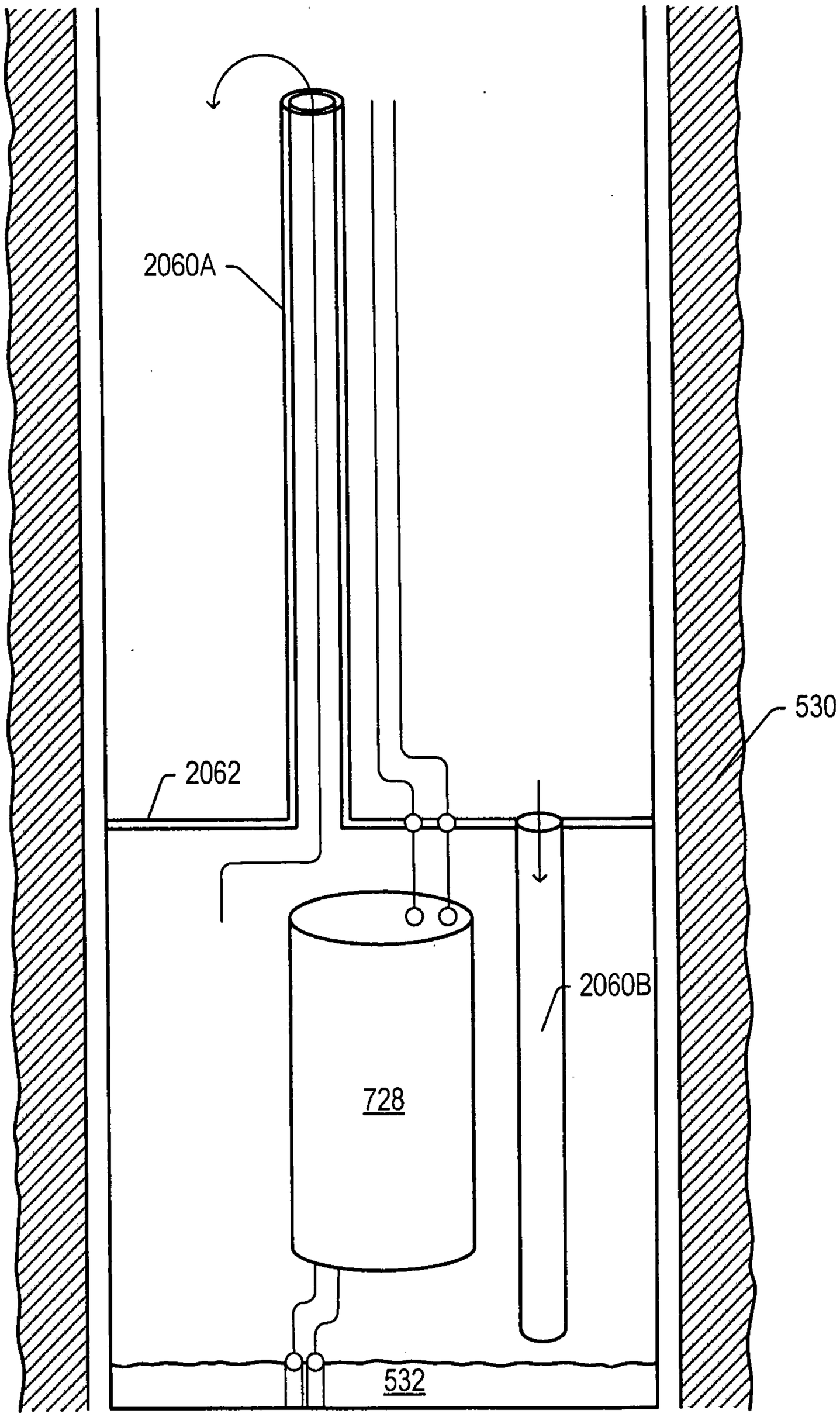


FIG. 129

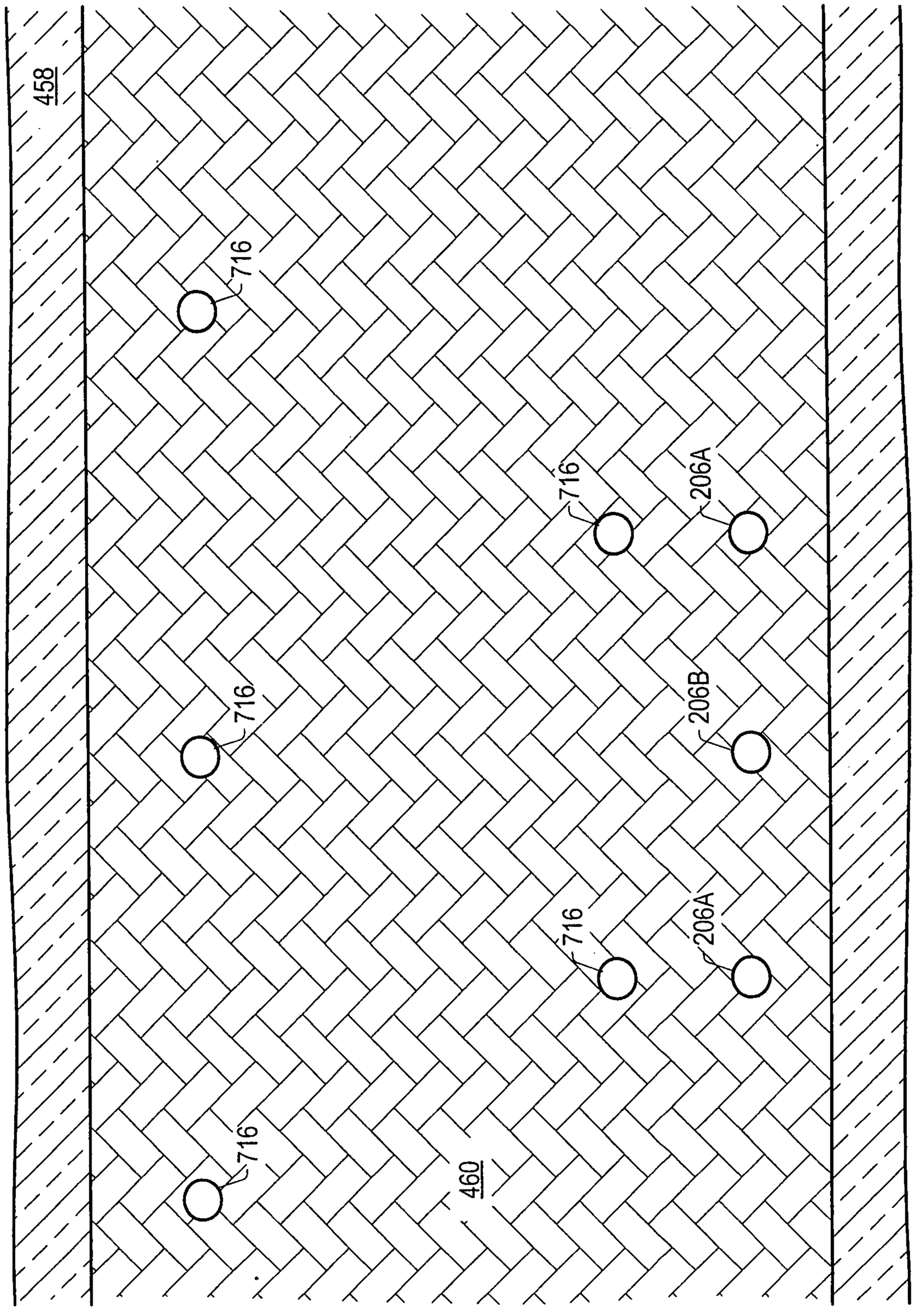


FIG. 130

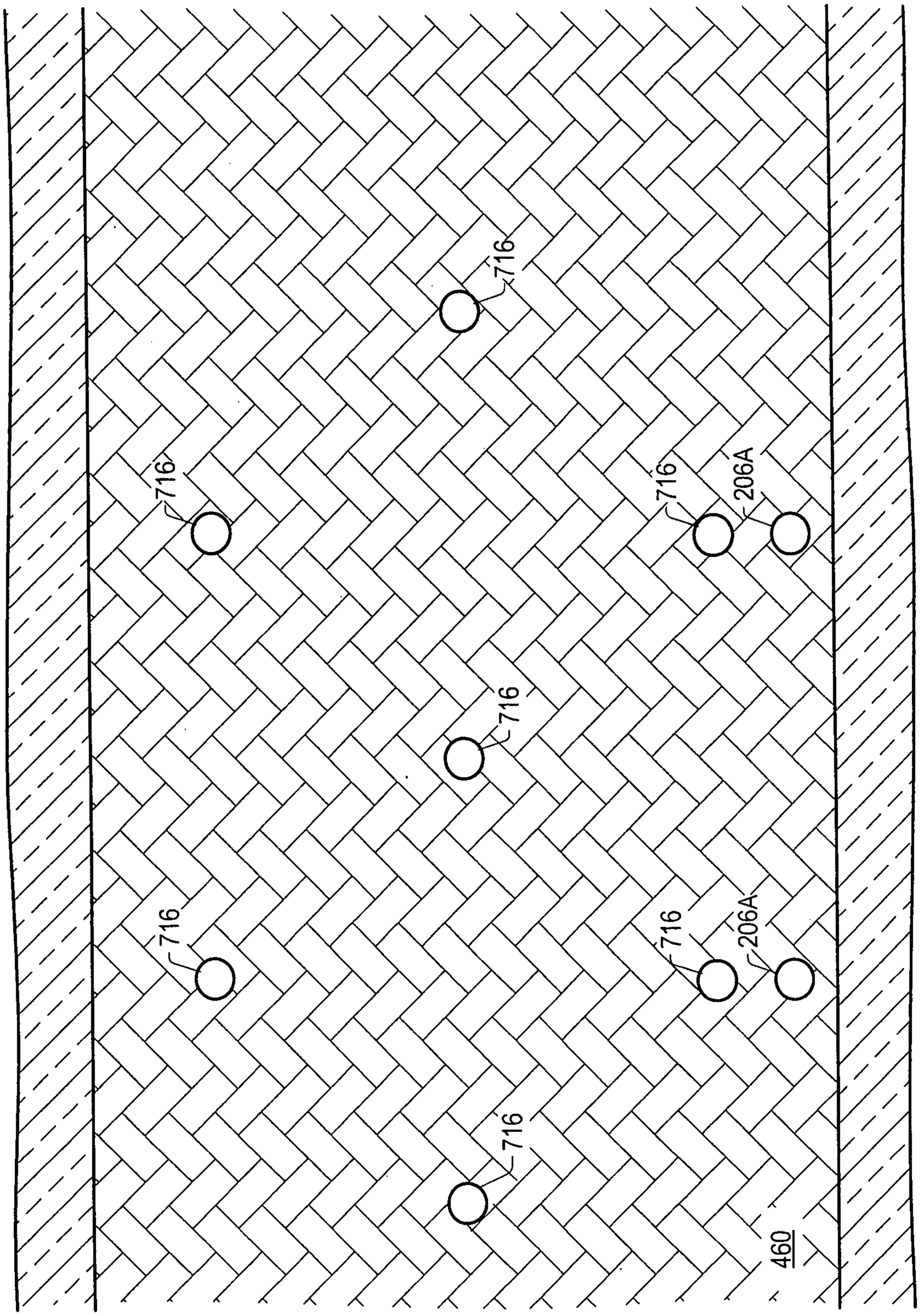


FIG. 131

FIG. 132

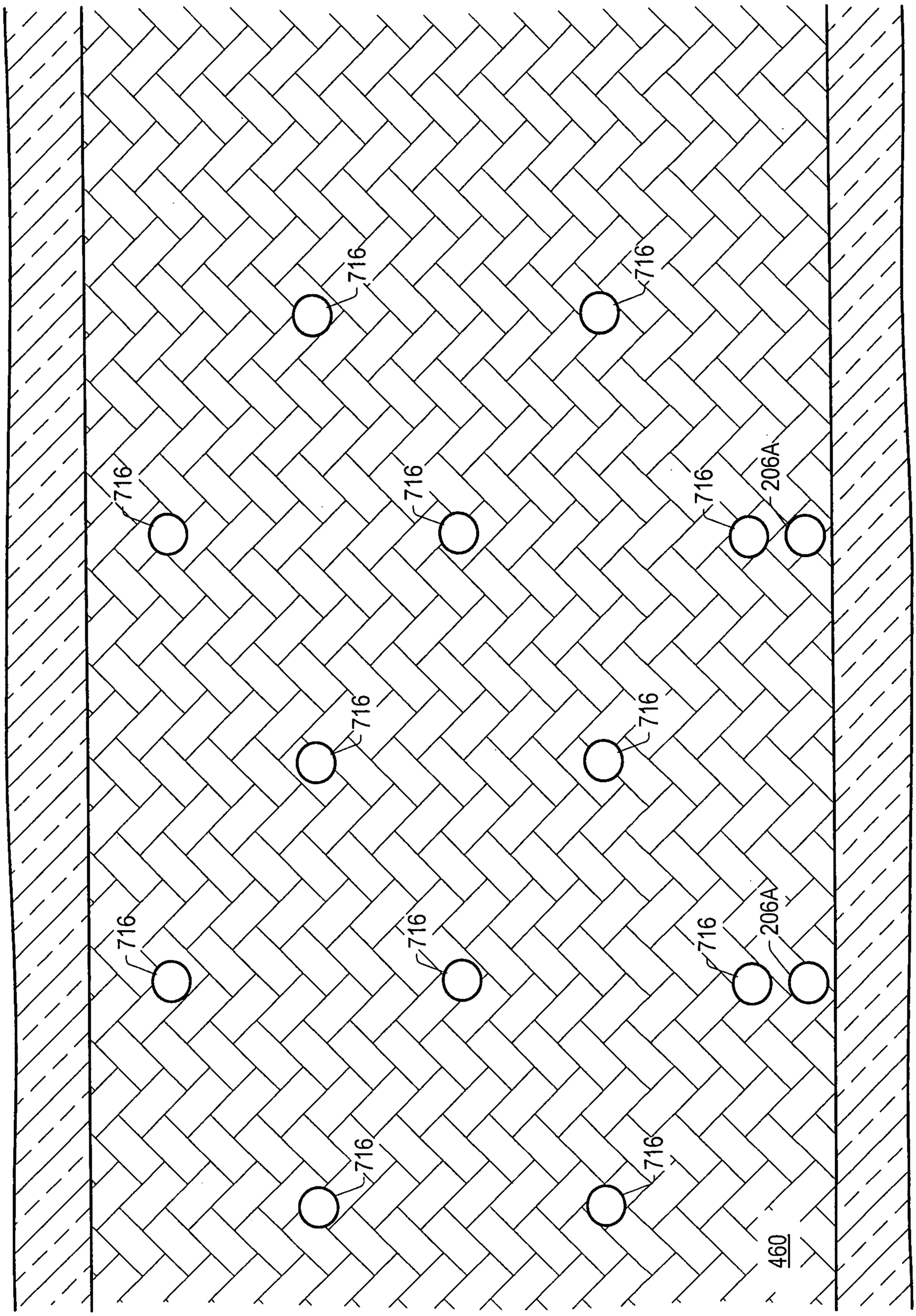
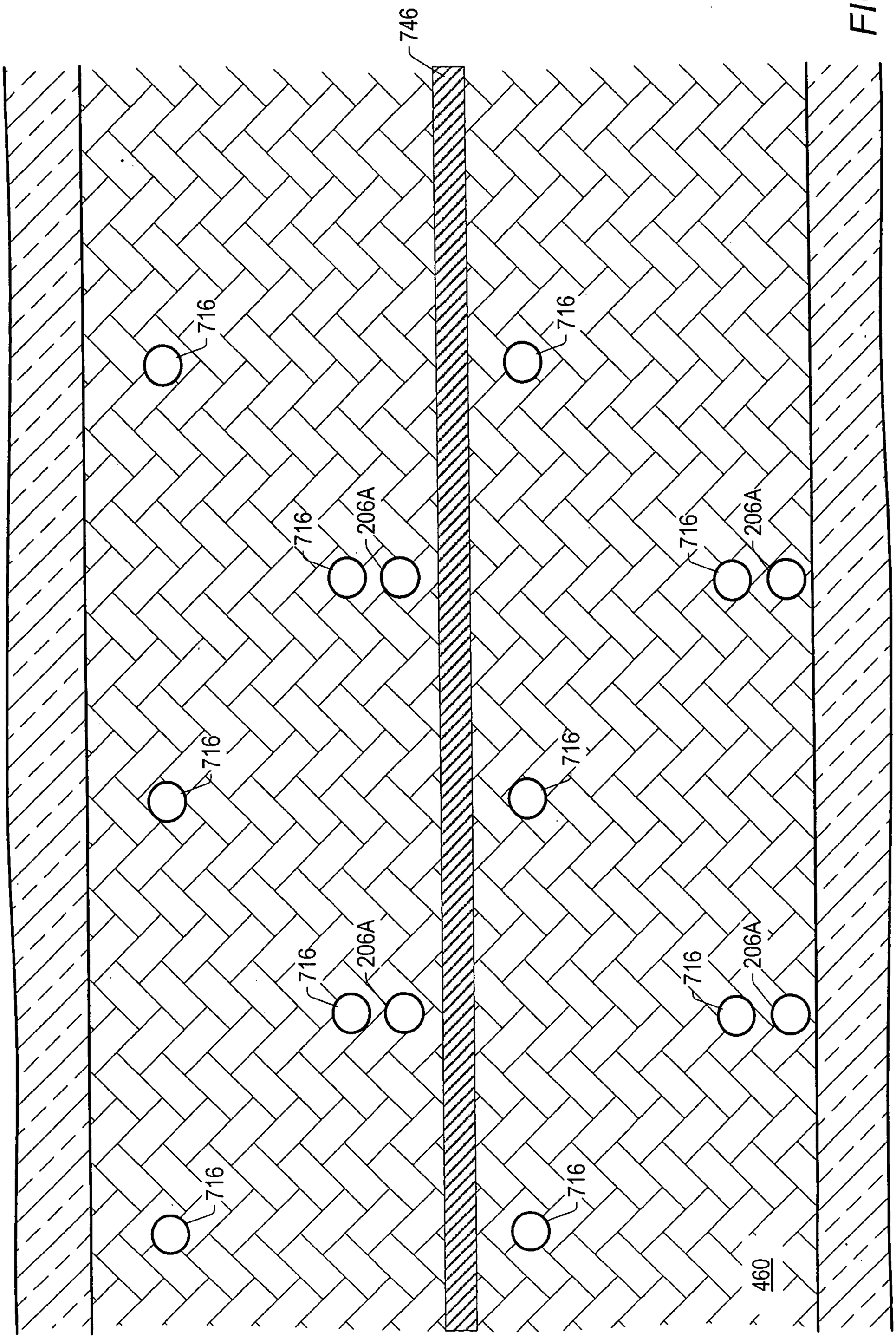


FIG. 133



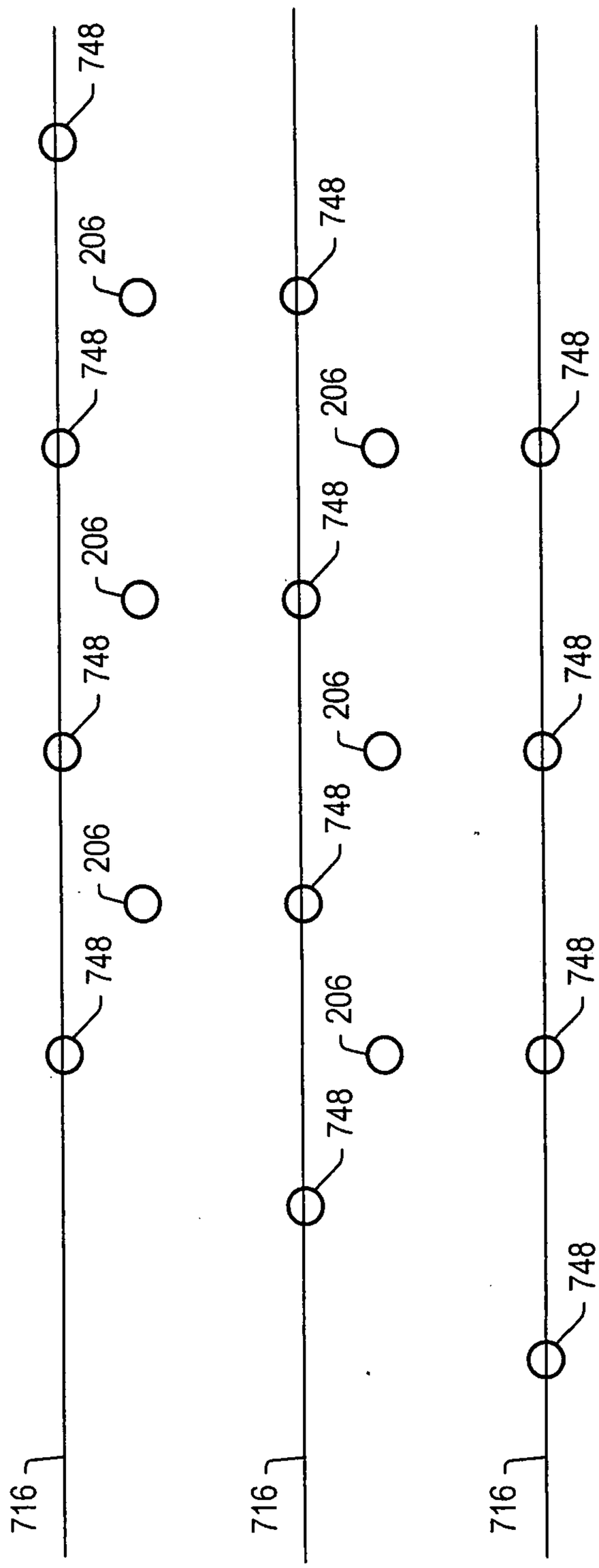
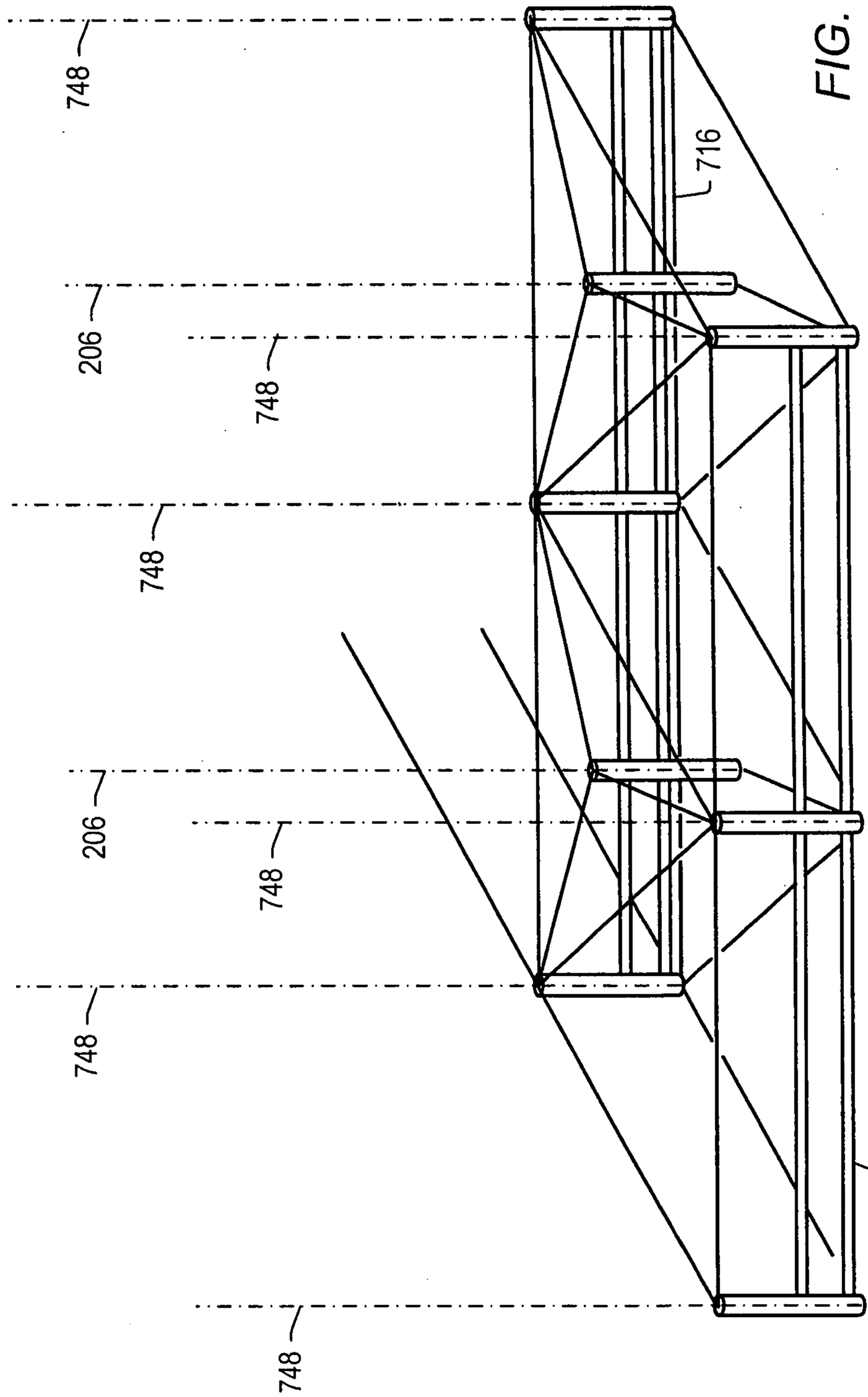

748
206
748
206
748
206

FIG. 135



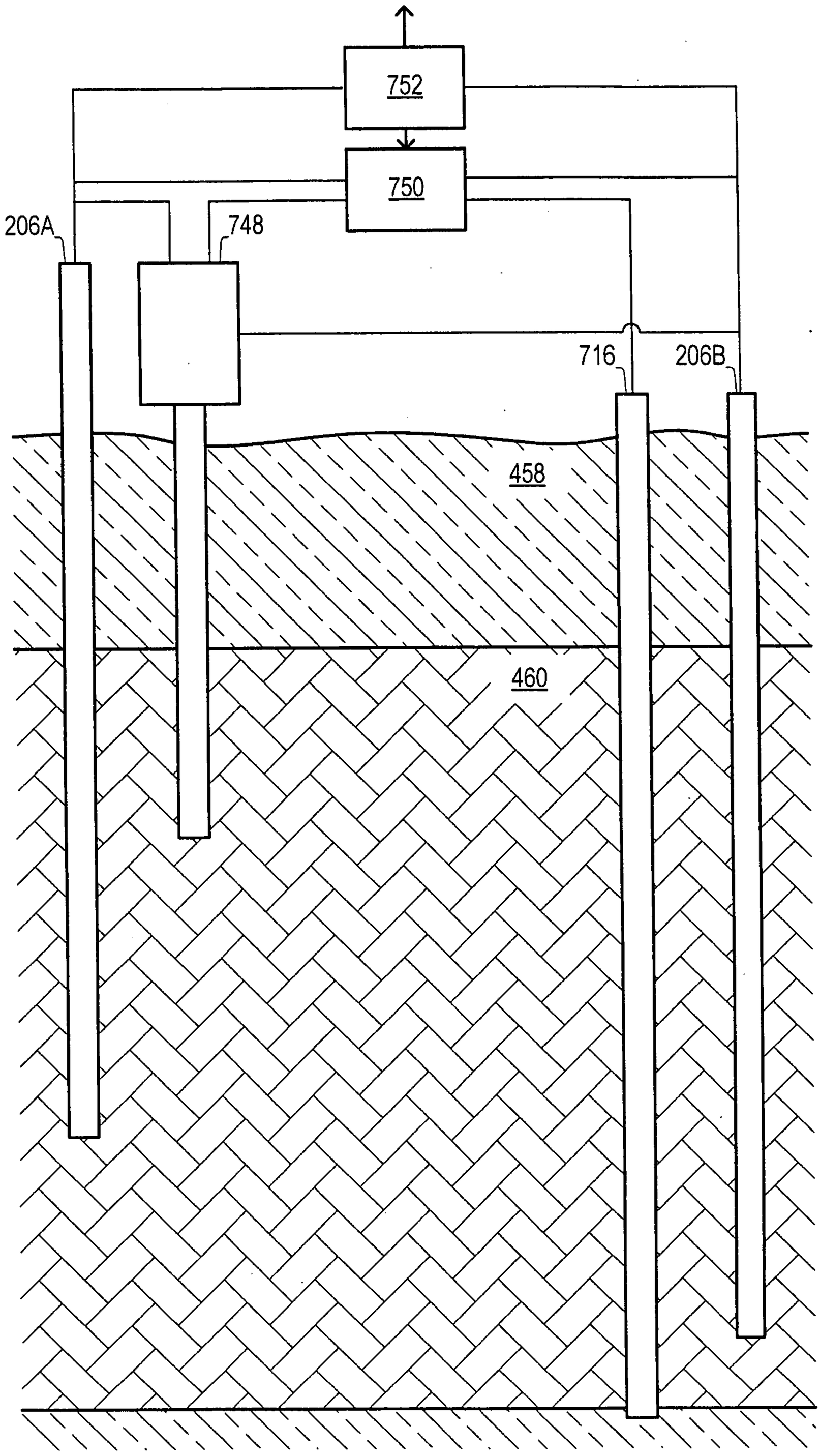


FIG. 136

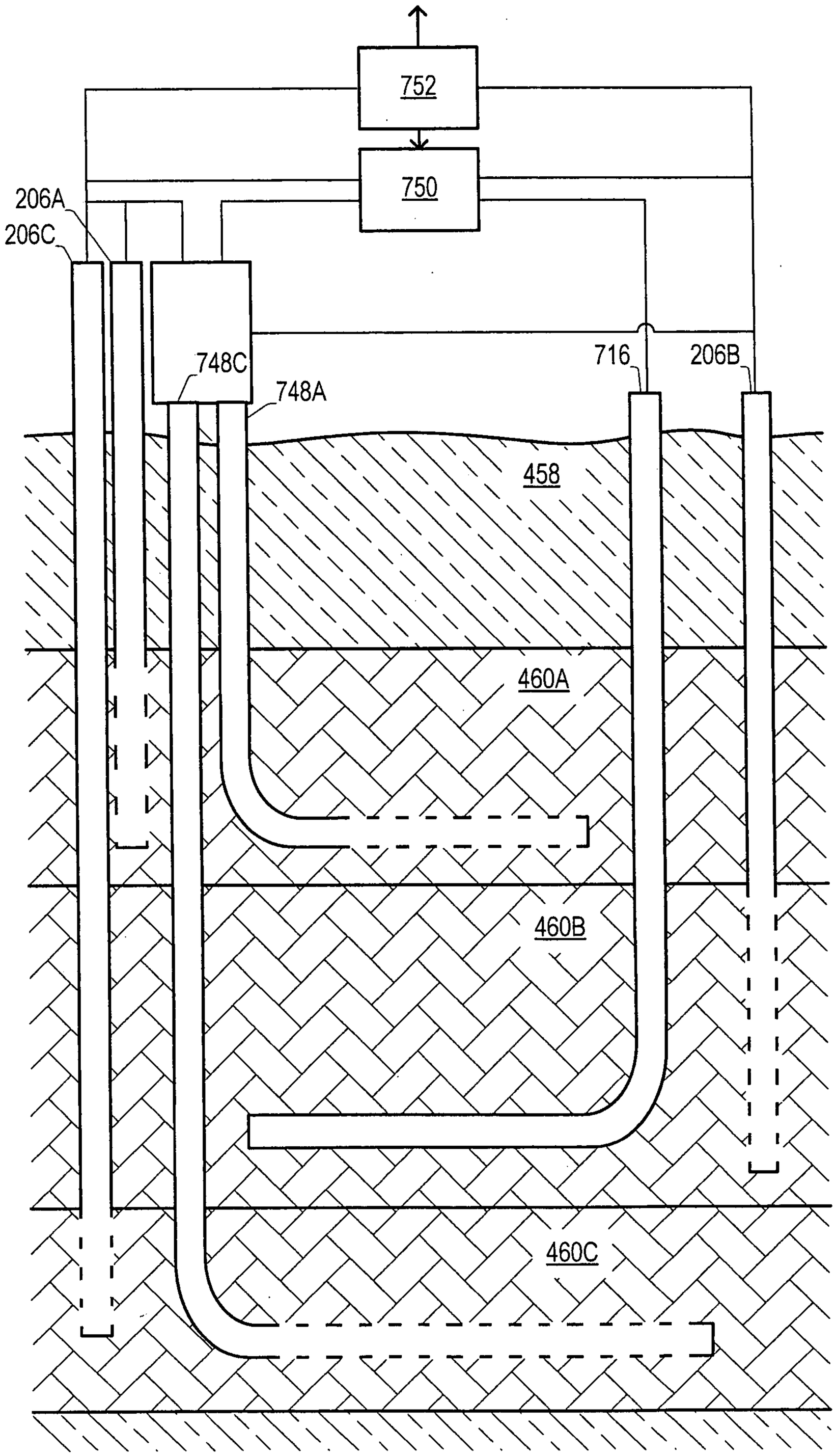


FIG. 137

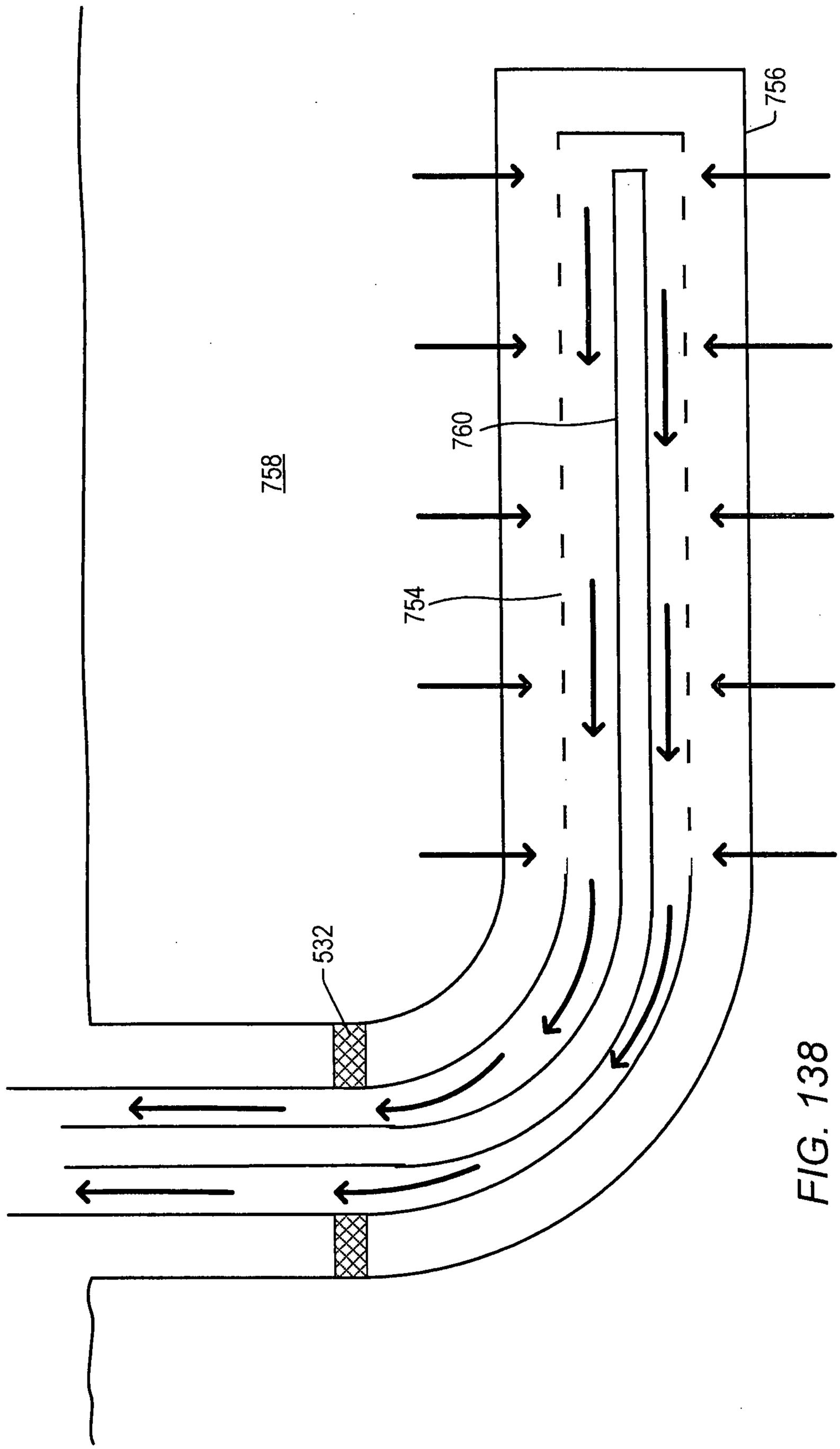


FIG. 138

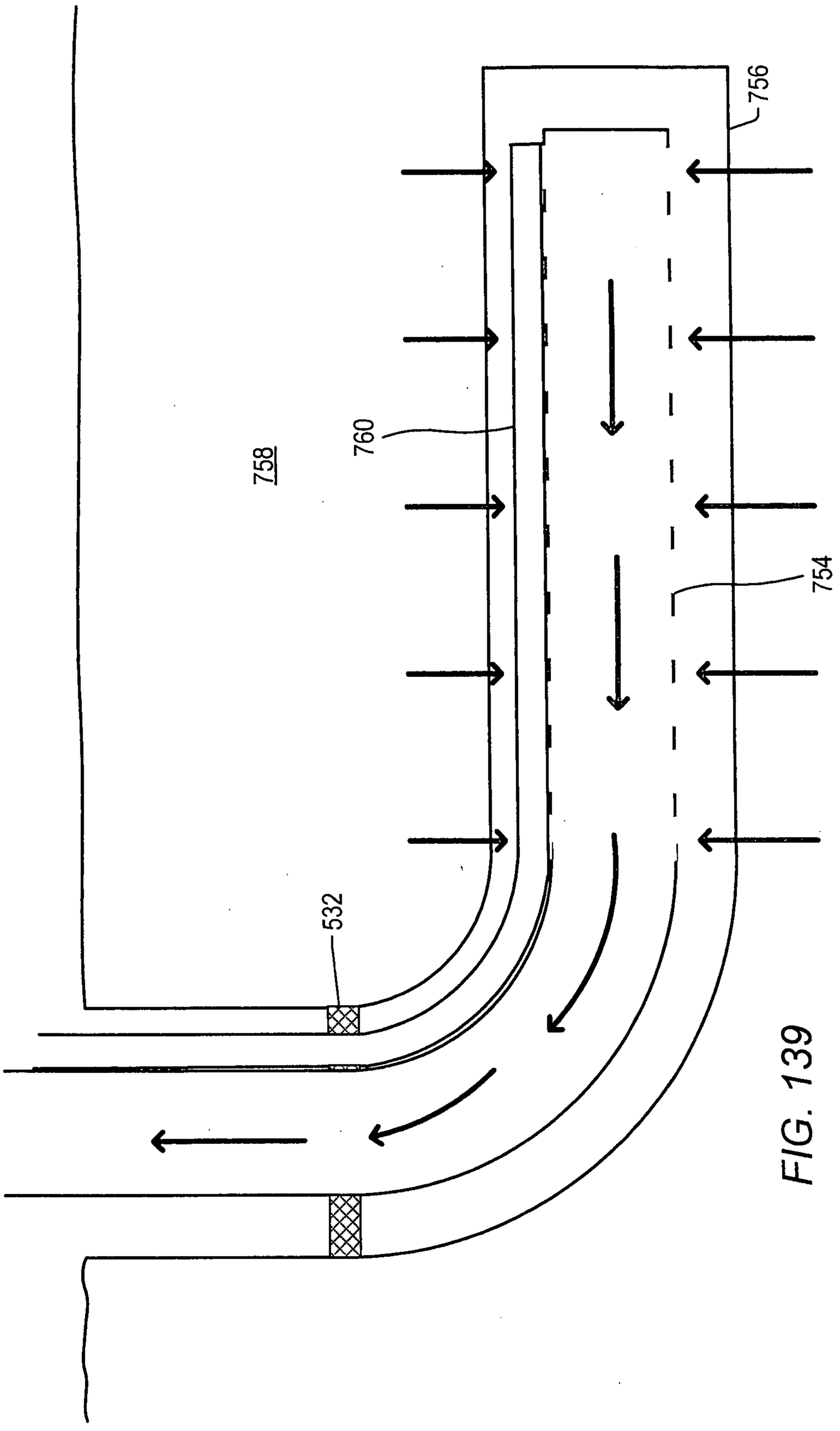


FIG. 139

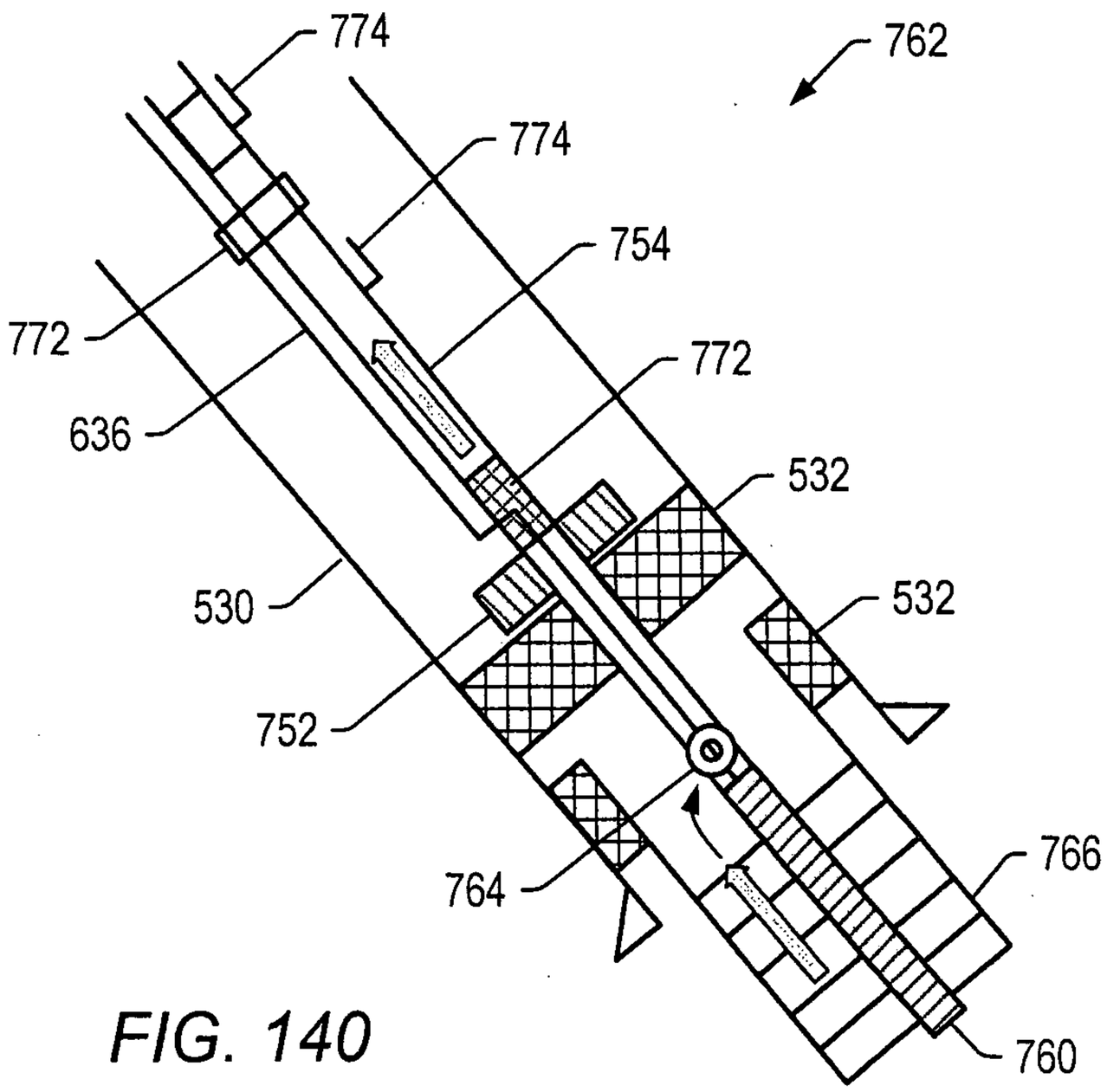


FIG. 140

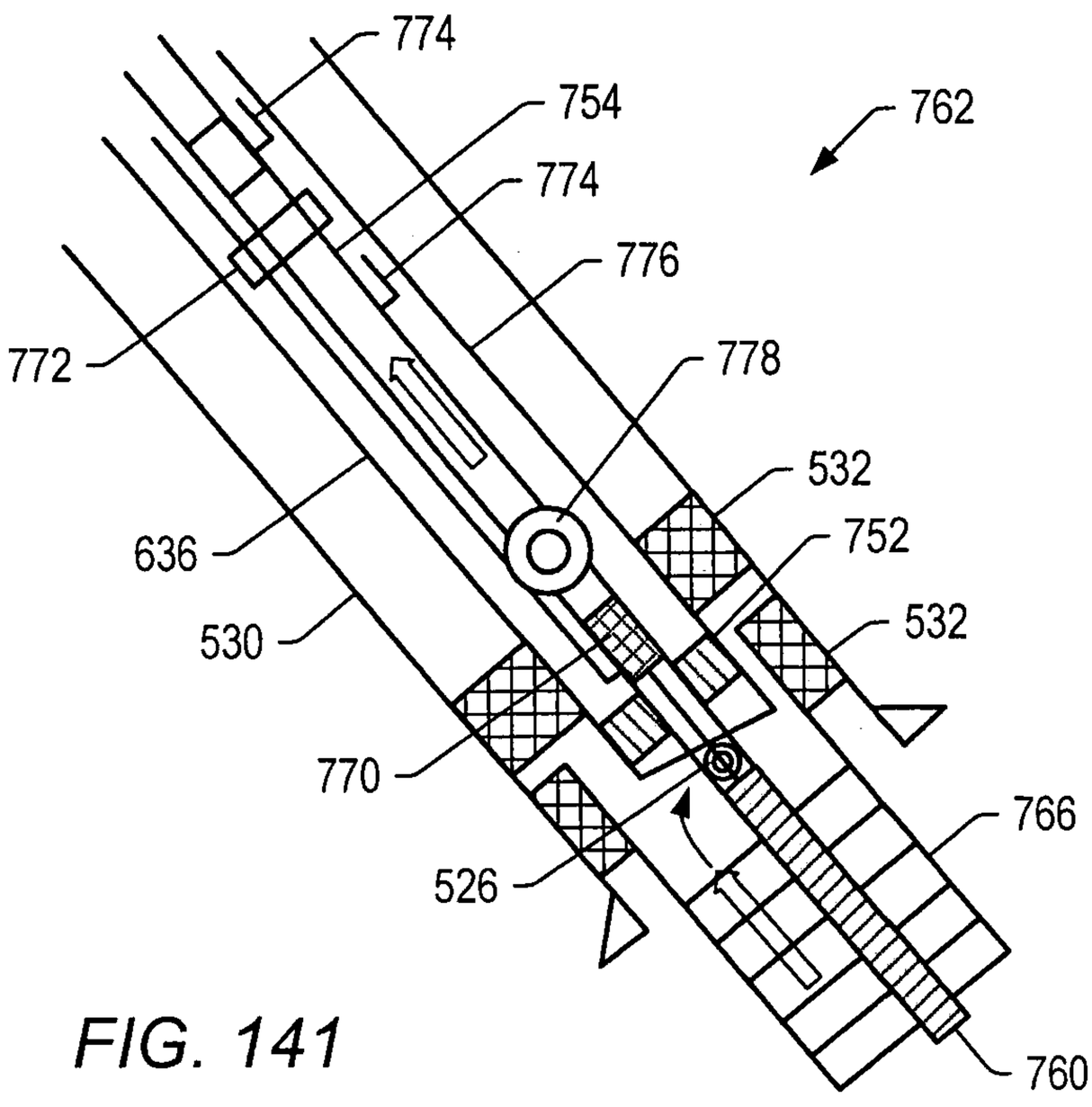


FIG. 141

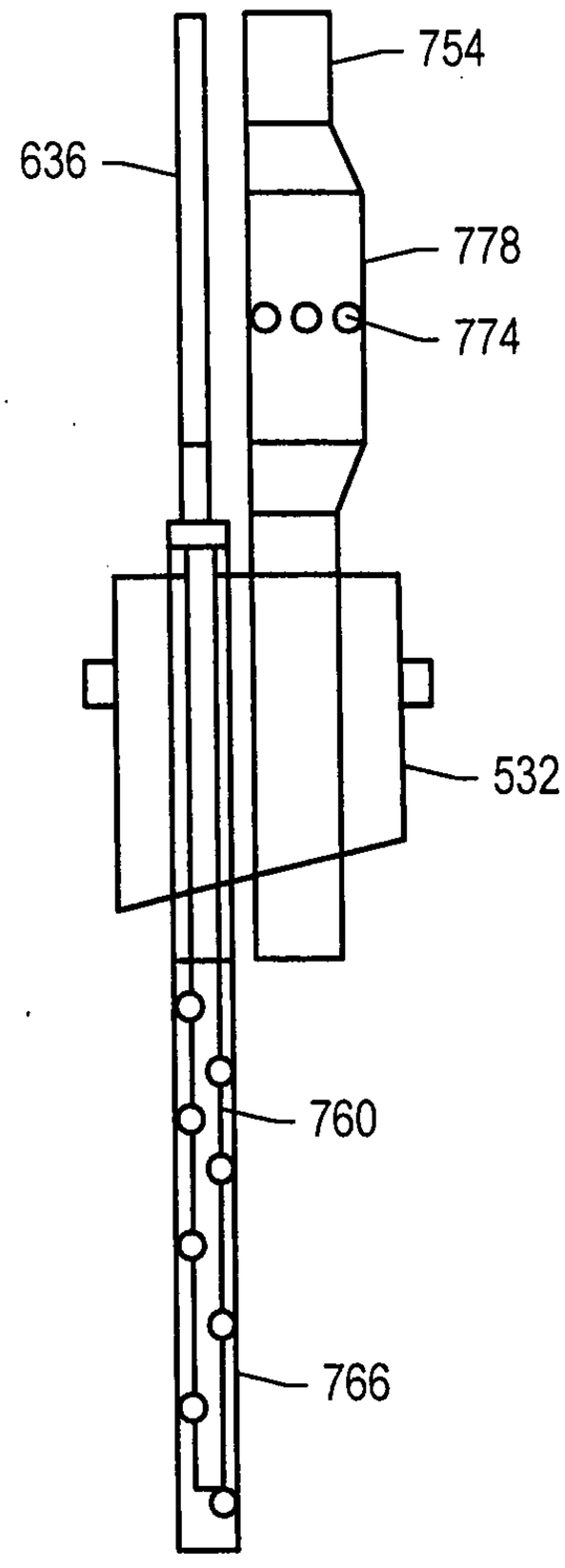


FIG. 142



FIG. 143

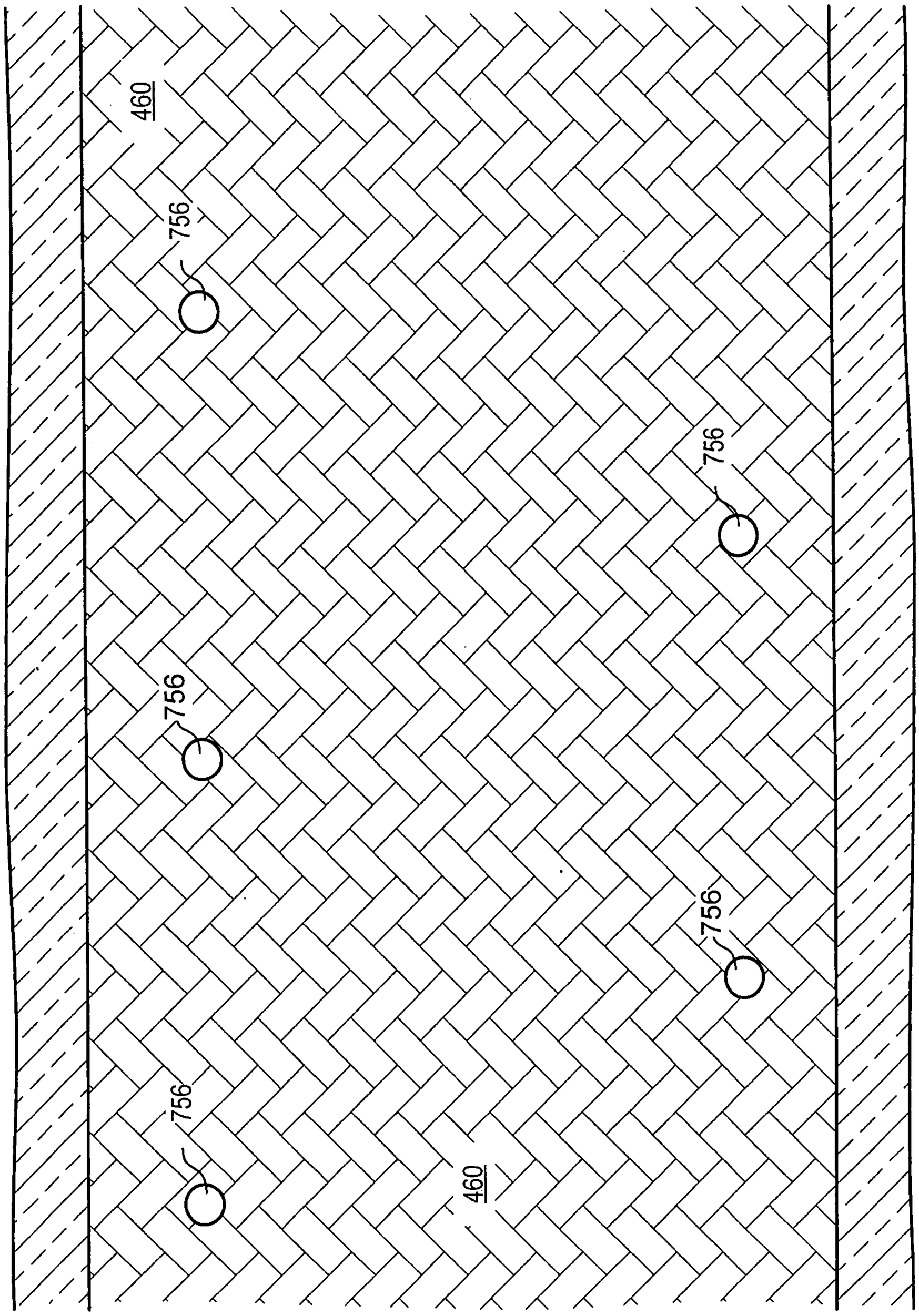


FIG. 144

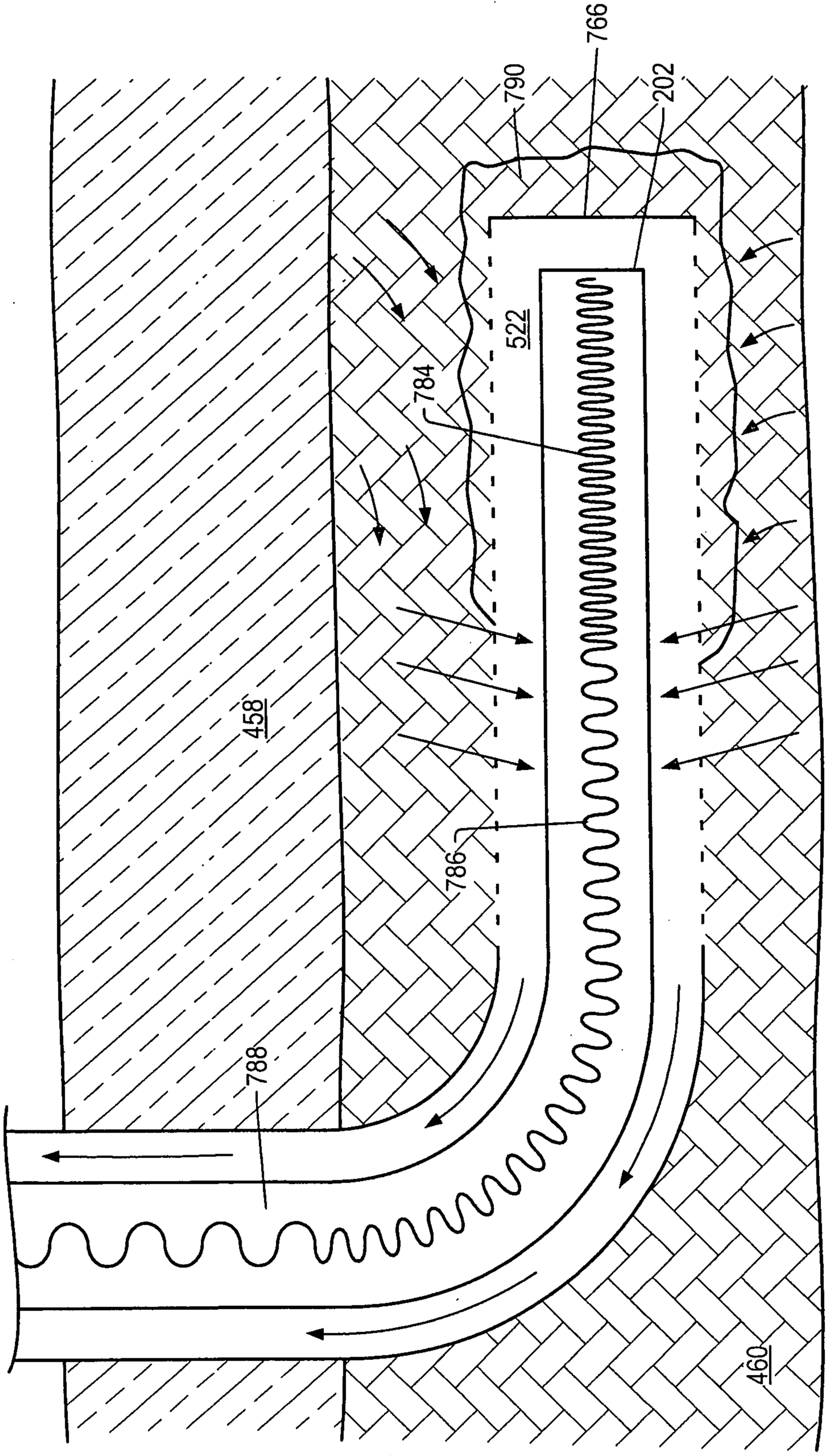


FIG. 145

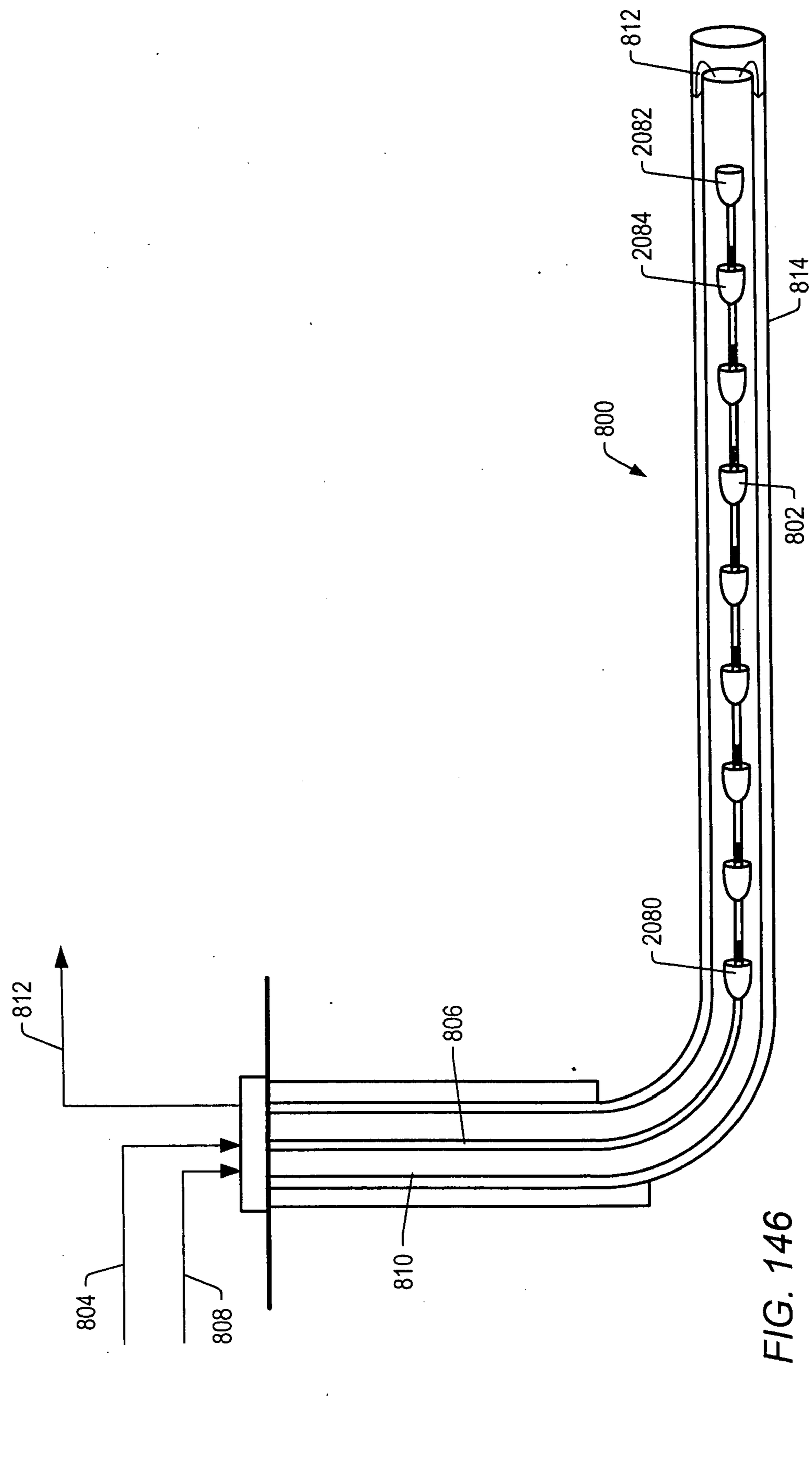


FIG. 146

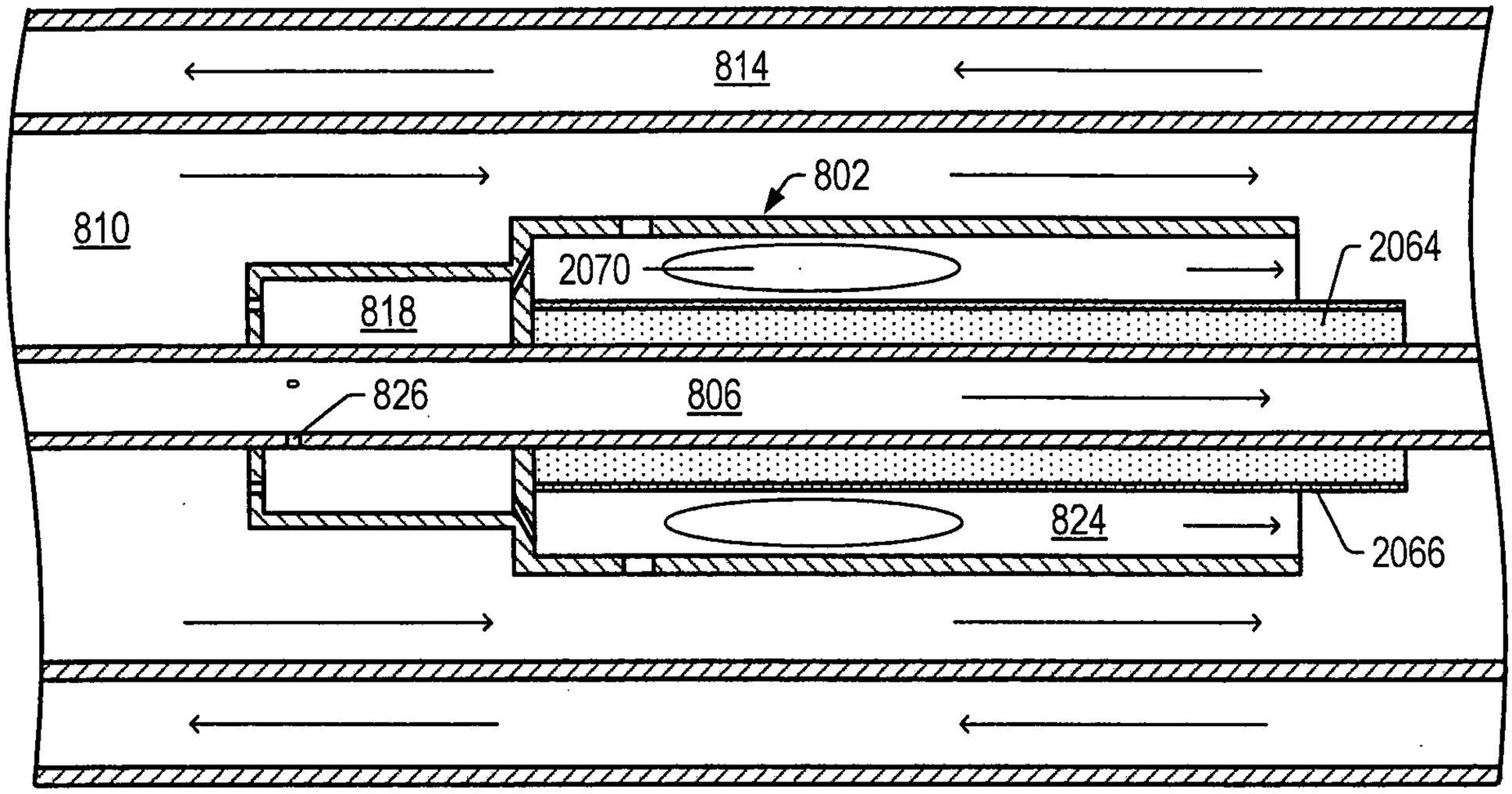


FIG. 147

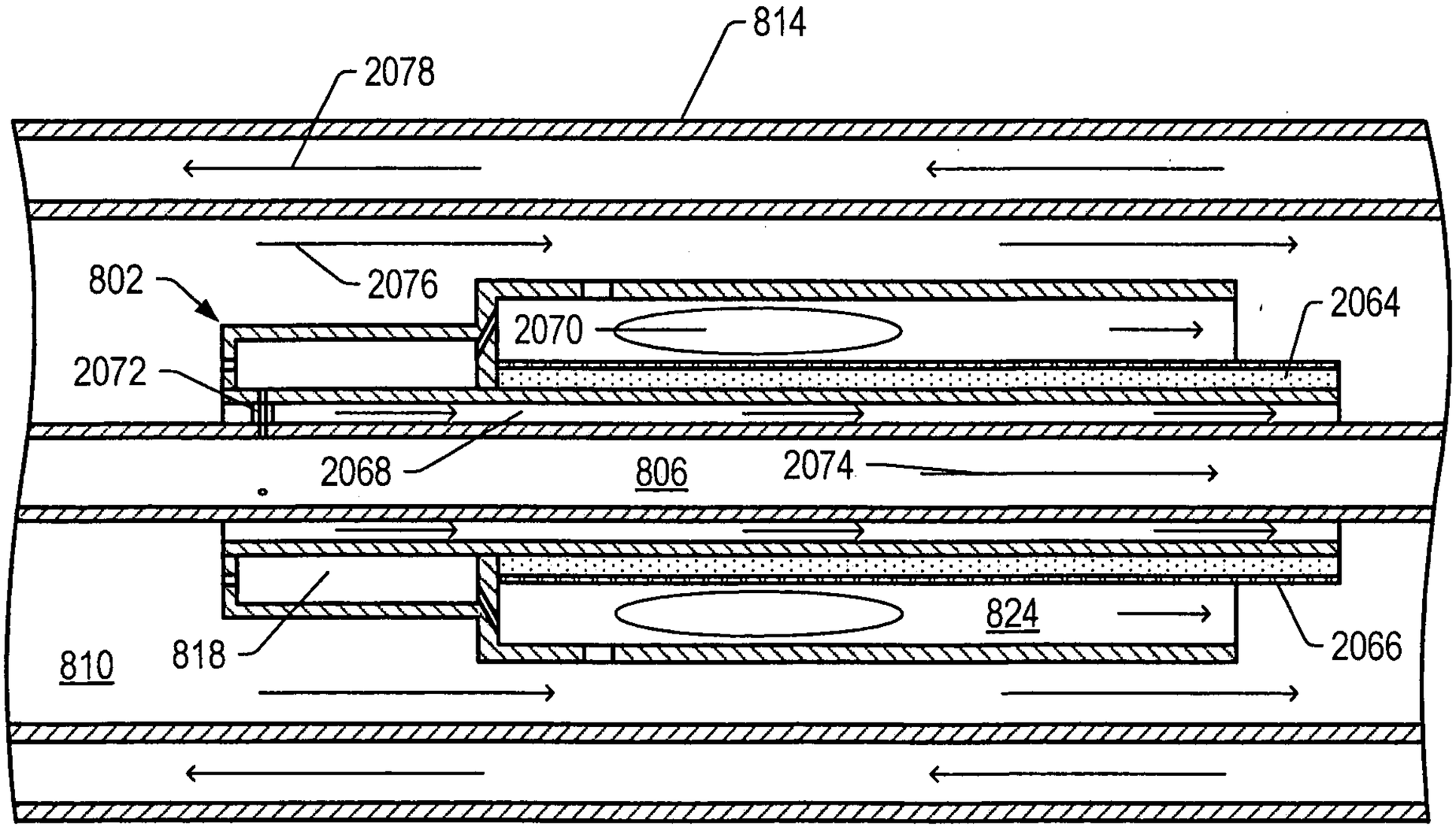


FIG. 148

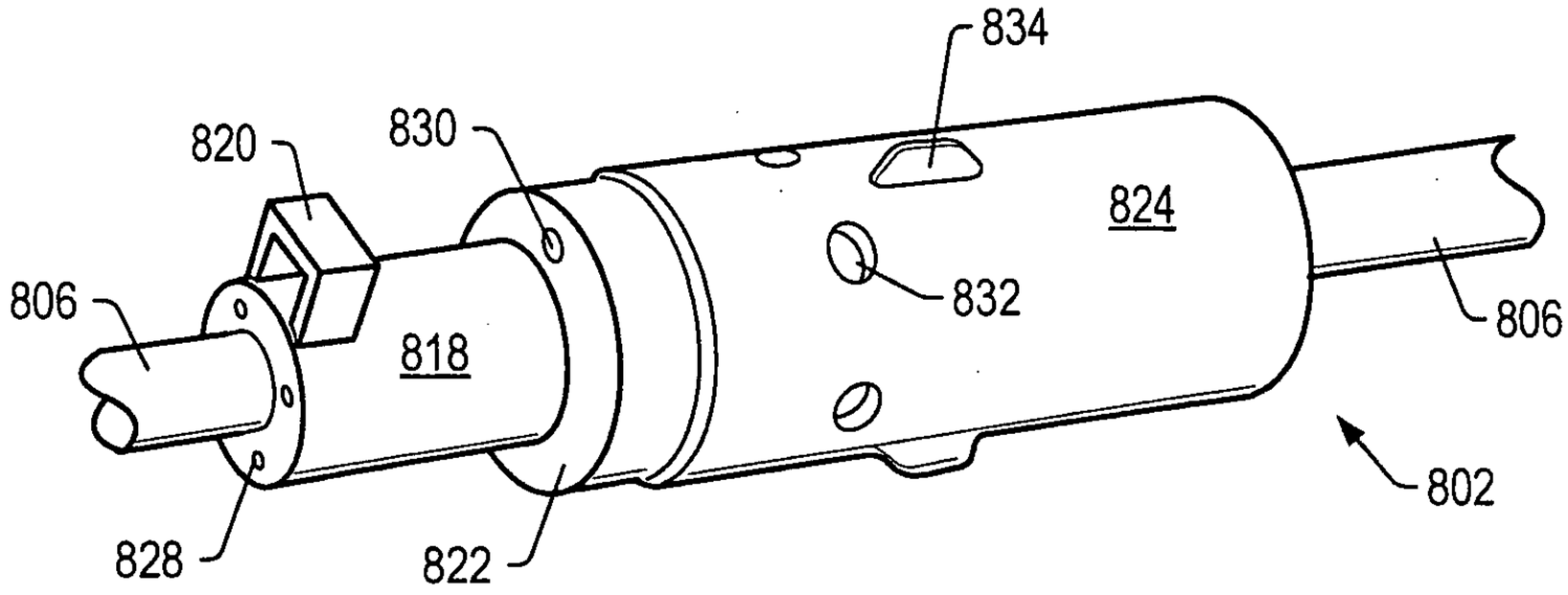


FIG. 149

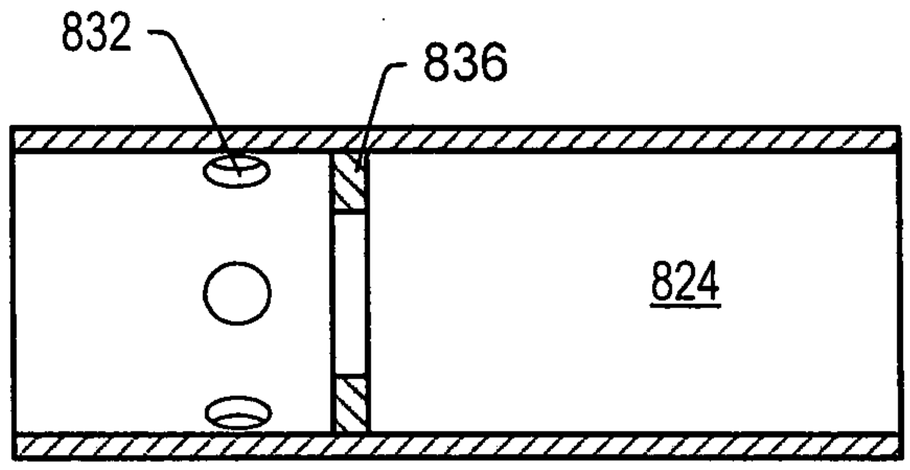


FIG. 150

FIG. 151

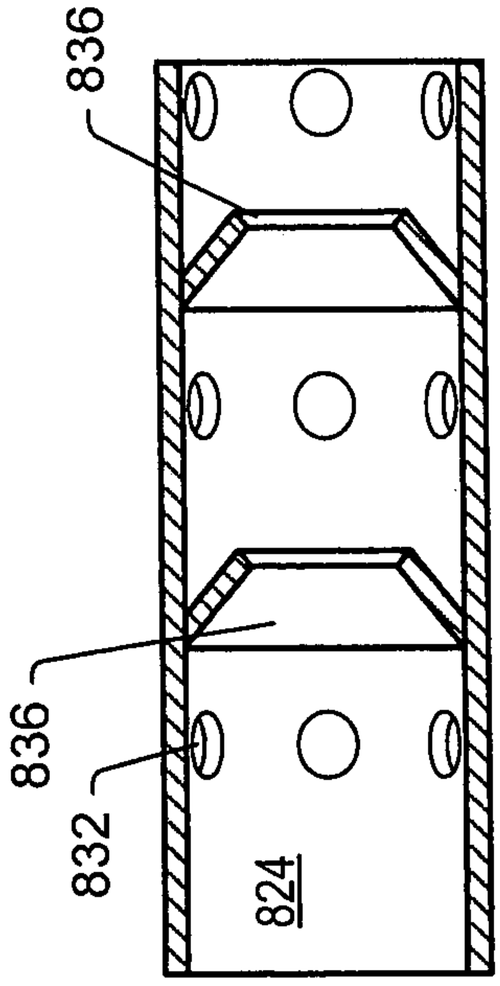


FIG. 153

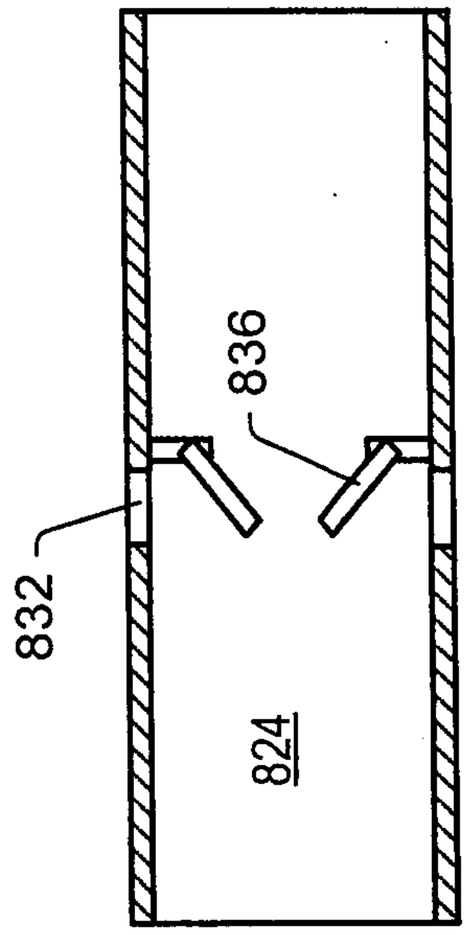


FIG. 155

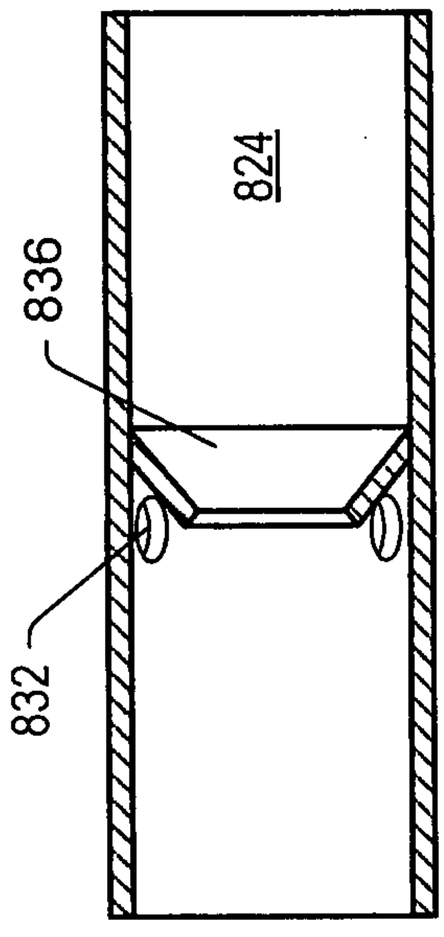


FIG. 152

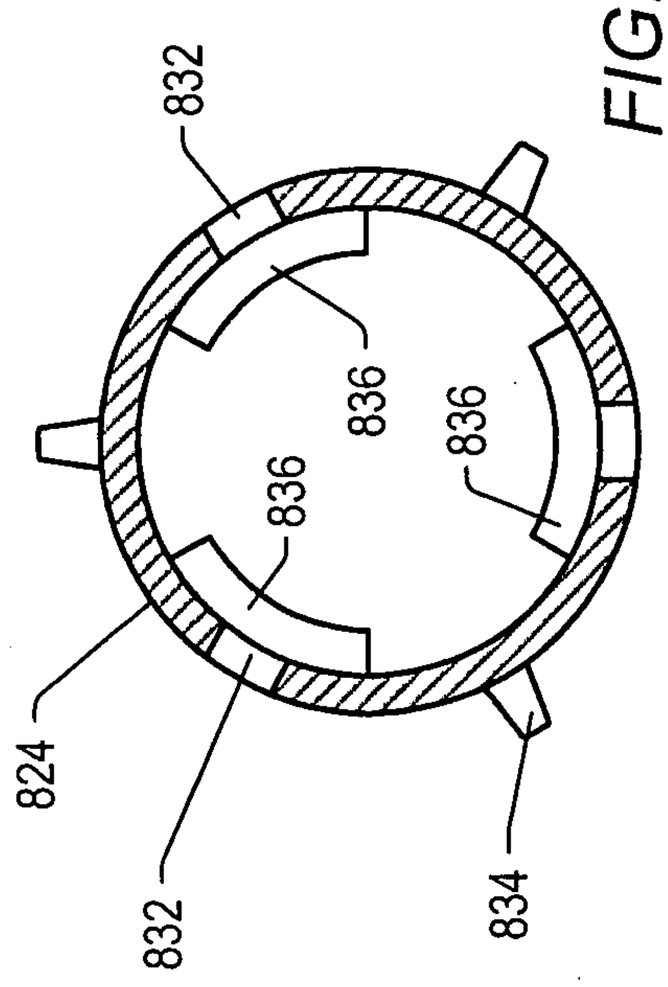


FIG. 154

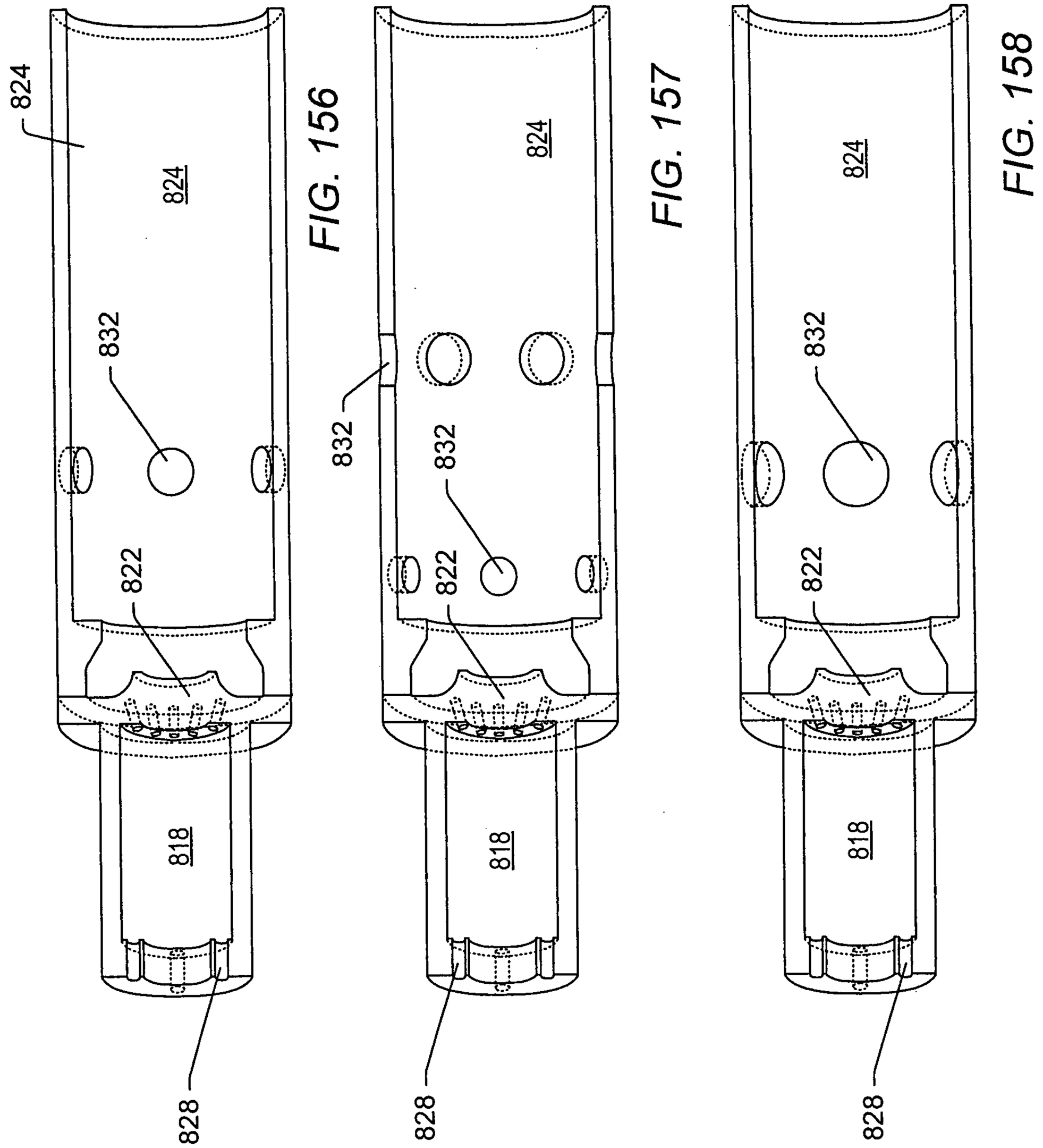


FIG. 156

FIG. 157

FIG. 158

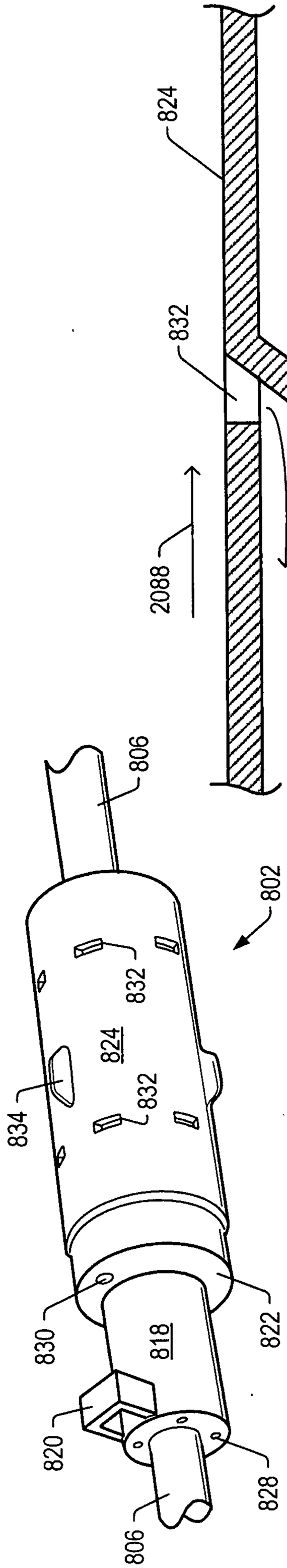


FIG. 159

FIG. 160

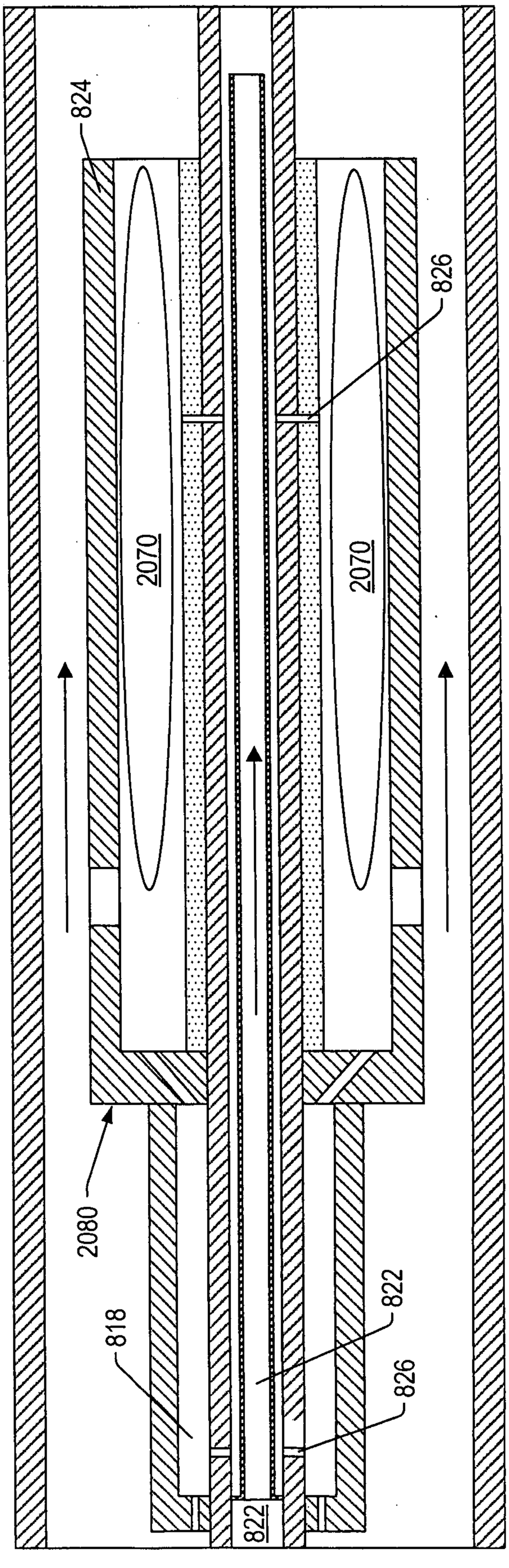


FIG. 161

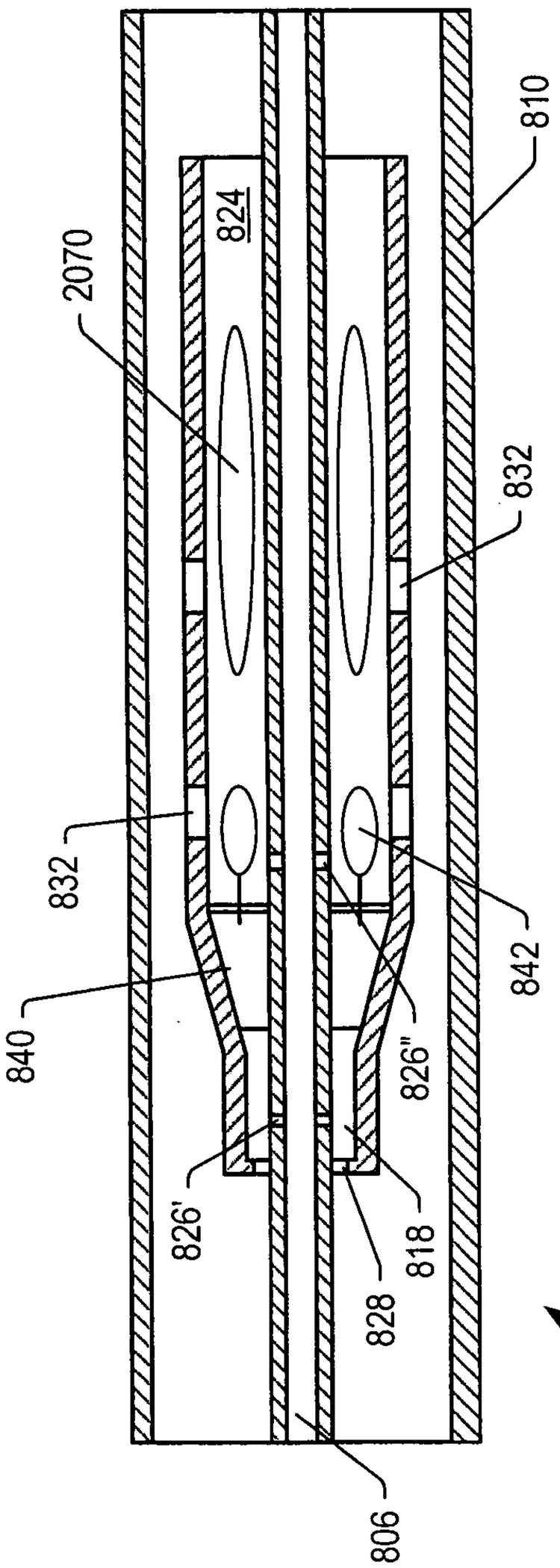


FIG. 162

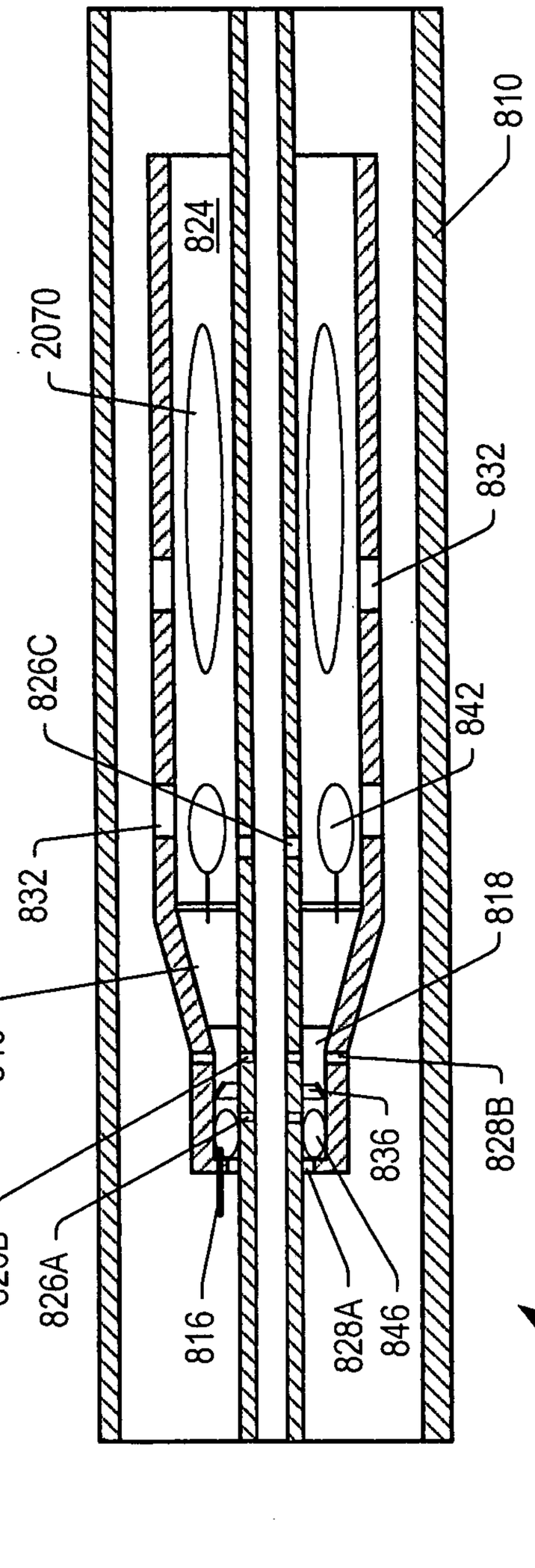


FIG. 163

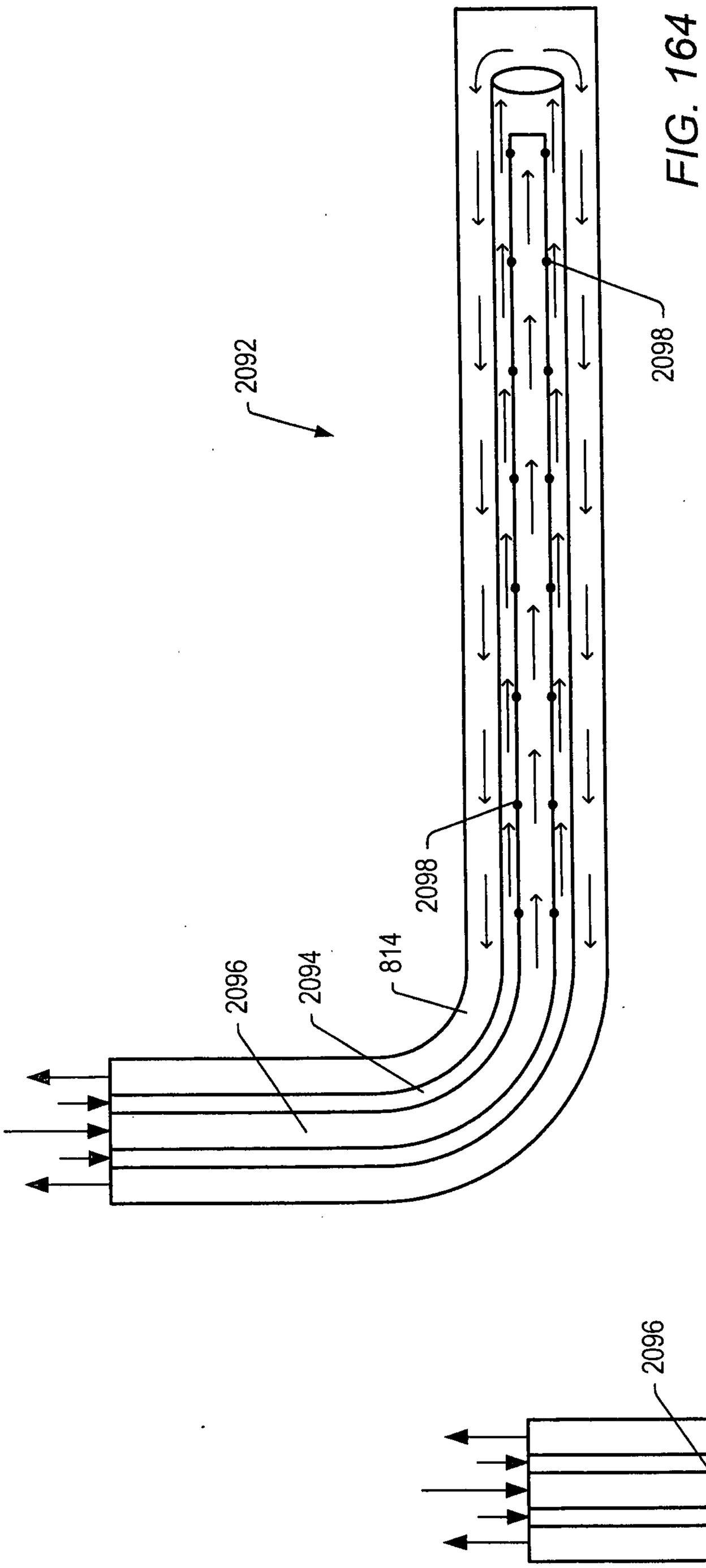


FIG. 164

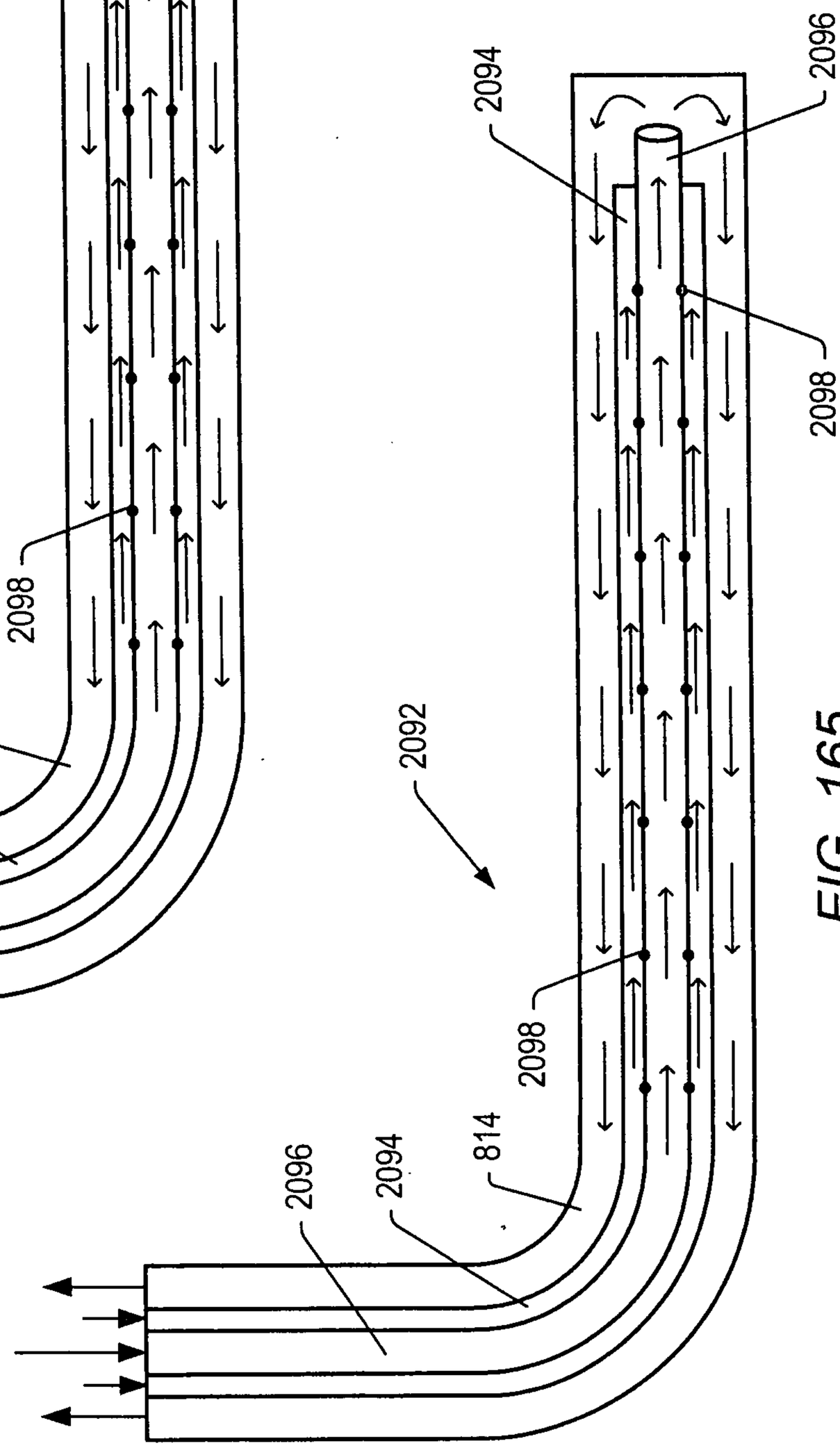


FIG. 165

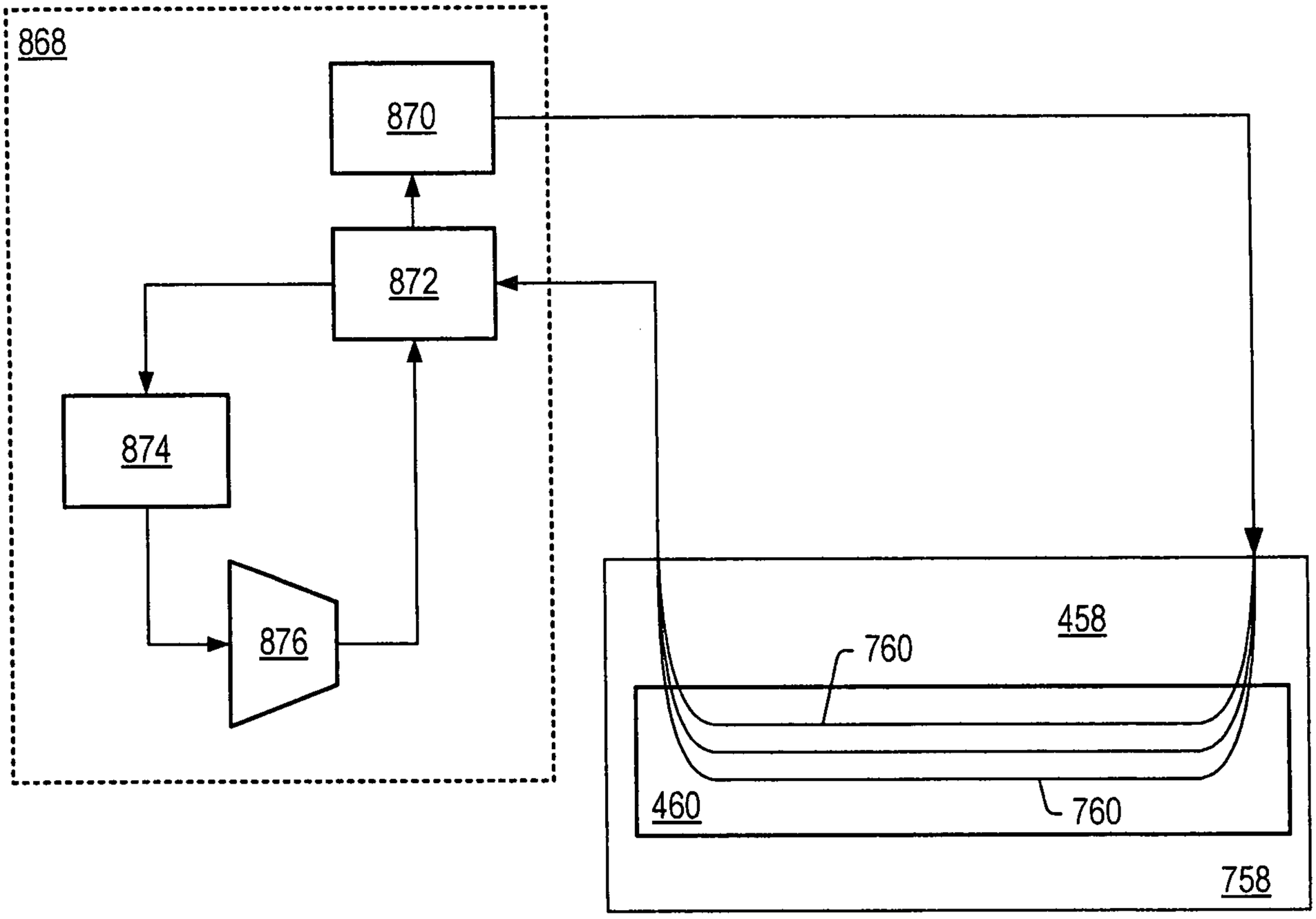


FIG. 166

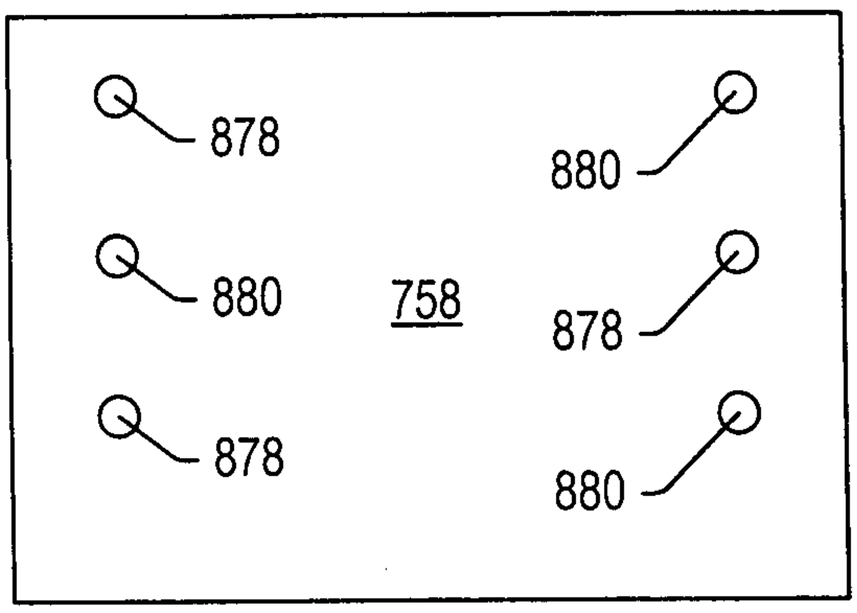


FIG. 167

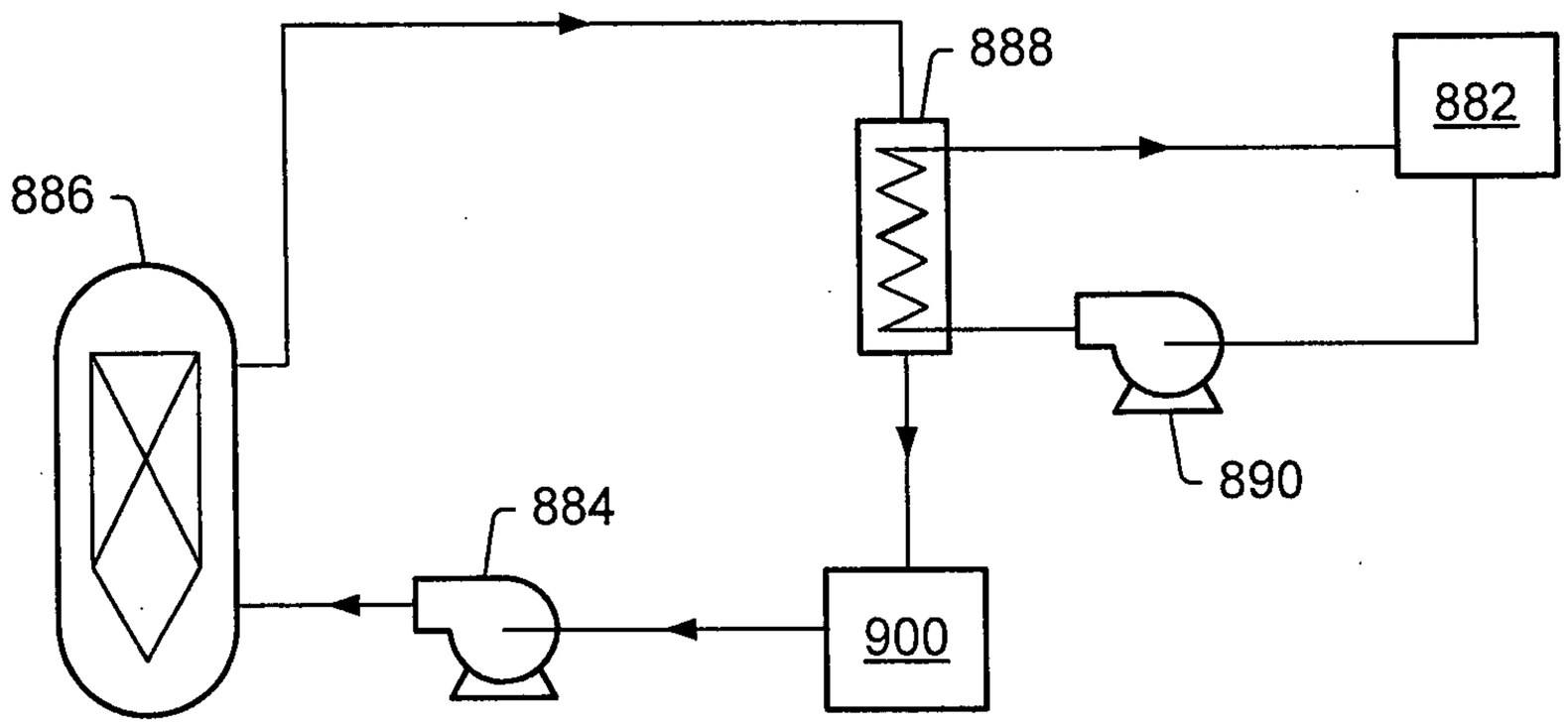


FIG. 168

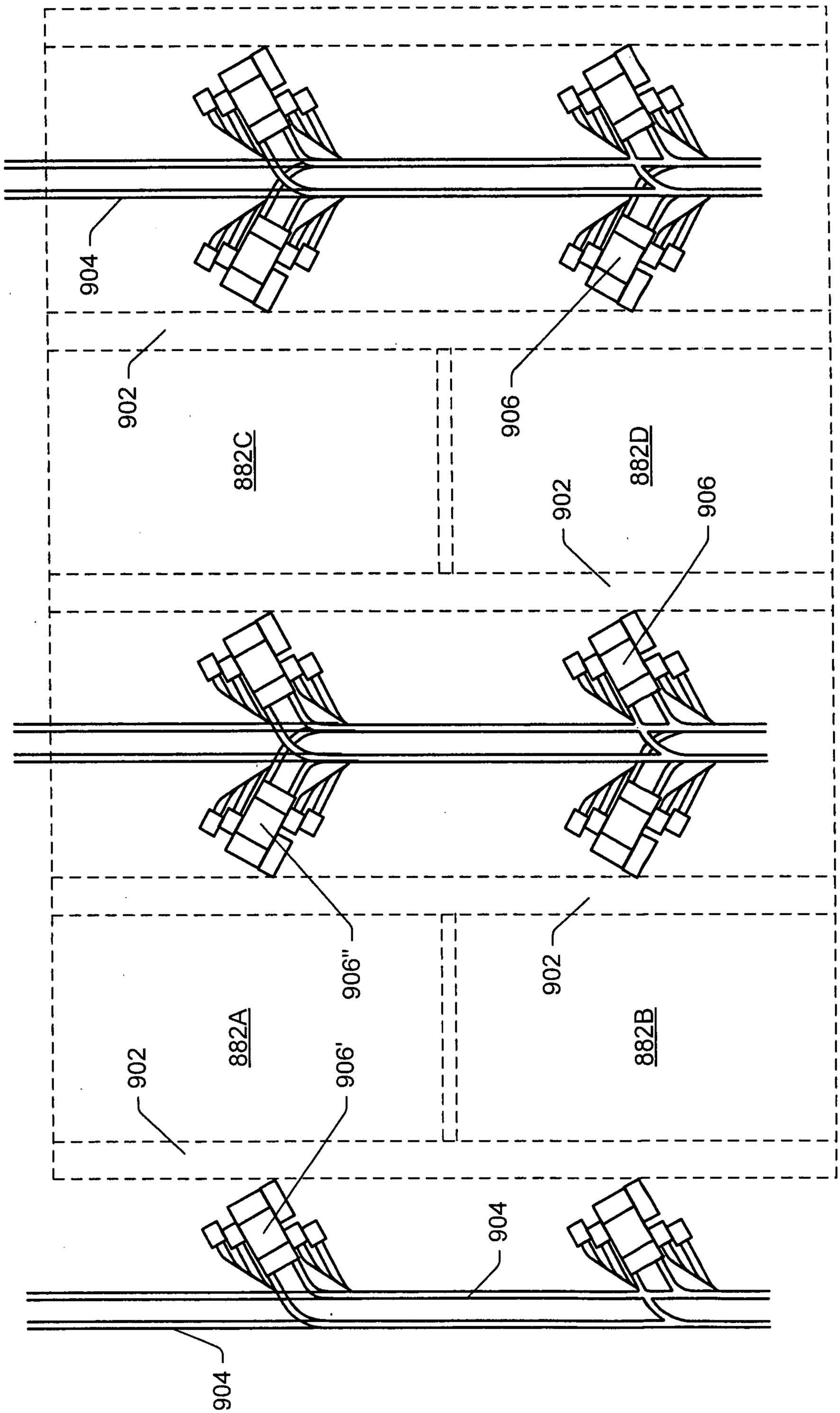


FIG. 169

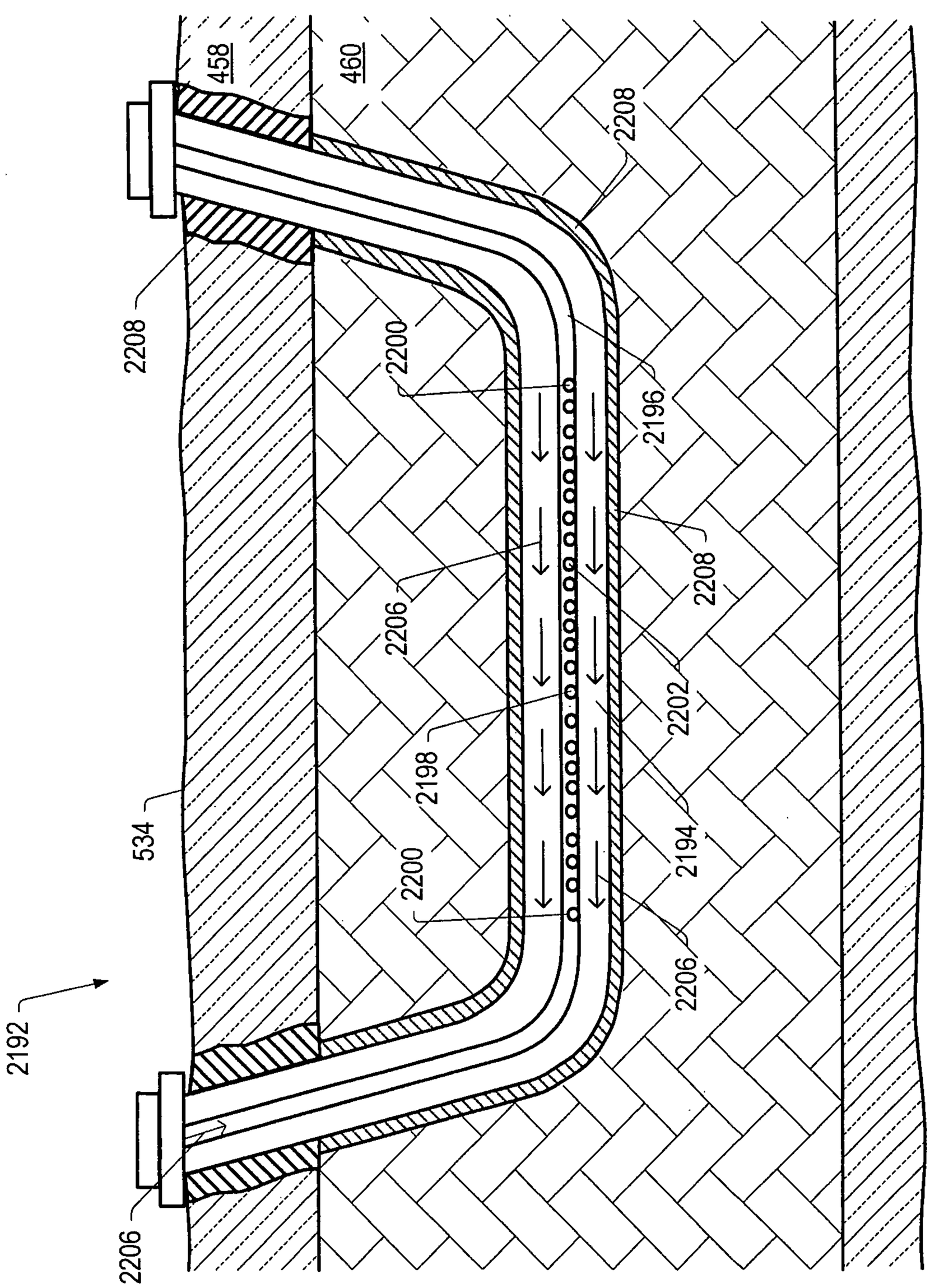

458
460
2208
2208
2200
2196
2208
2206
2202
2198
2194
534
2200
2206
2192
2206

FIG. 170

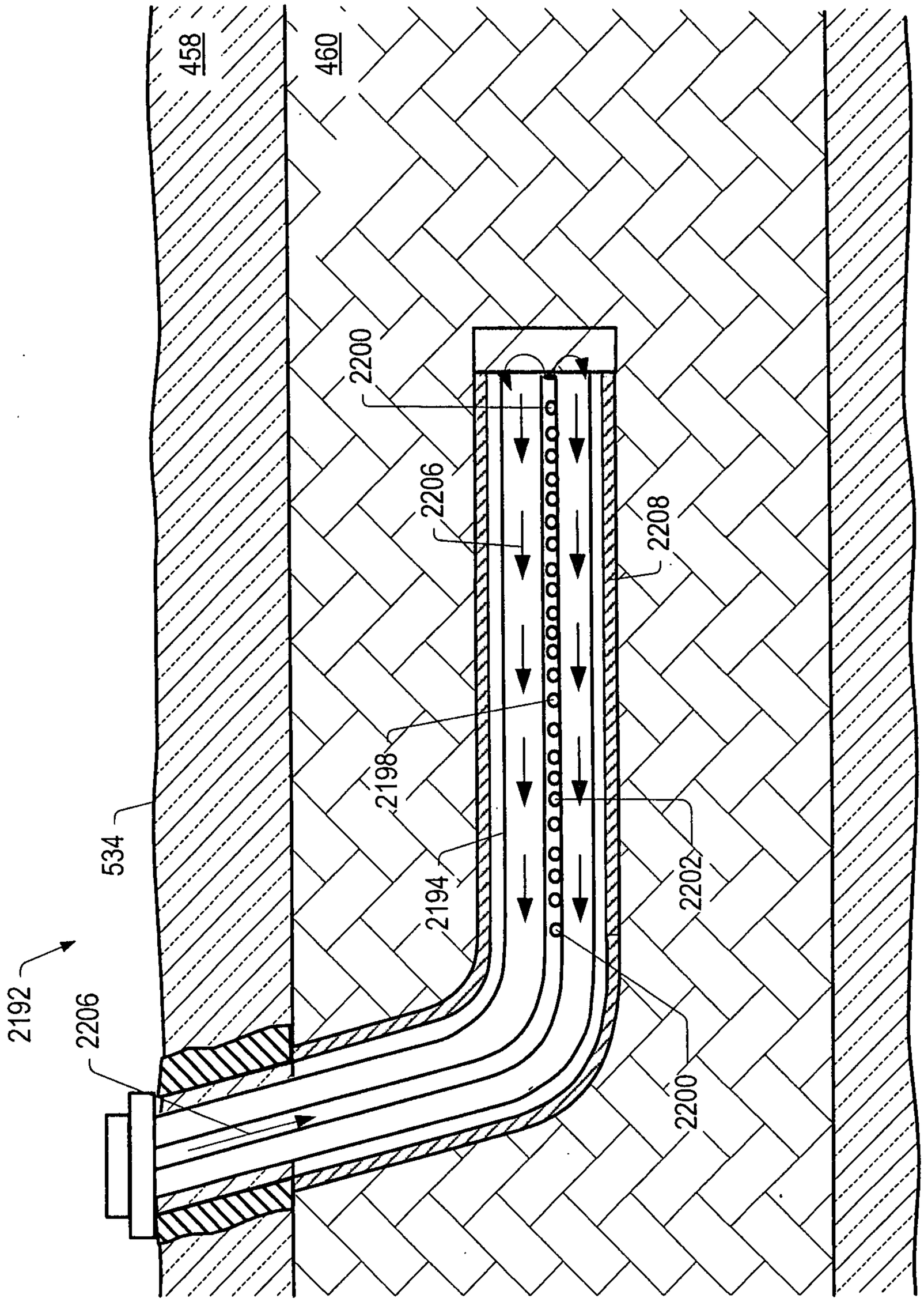


FIG. 171

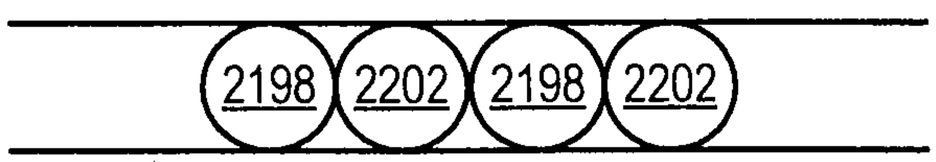


FIG. 172

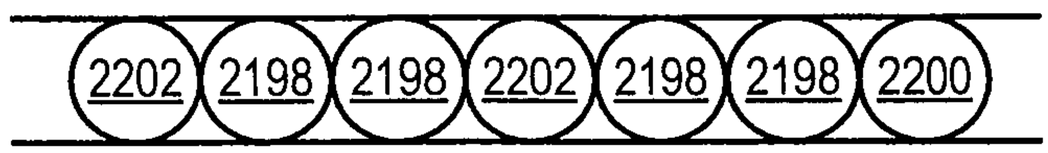


FIG. 173

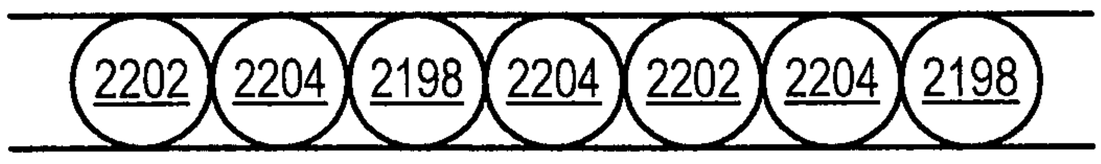


FIG. 174

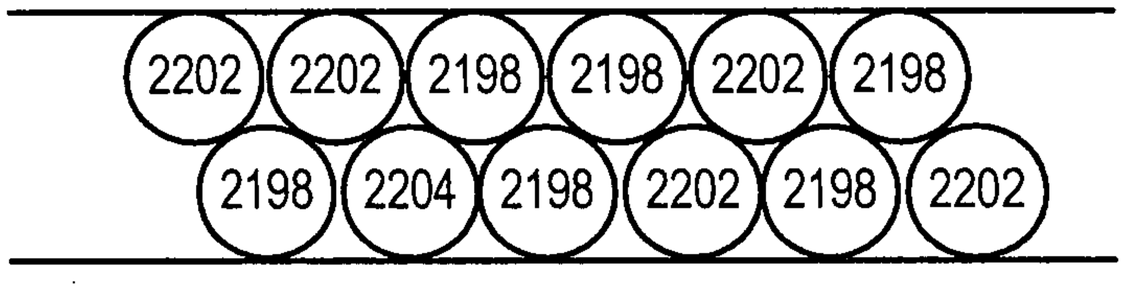


FIG. 175

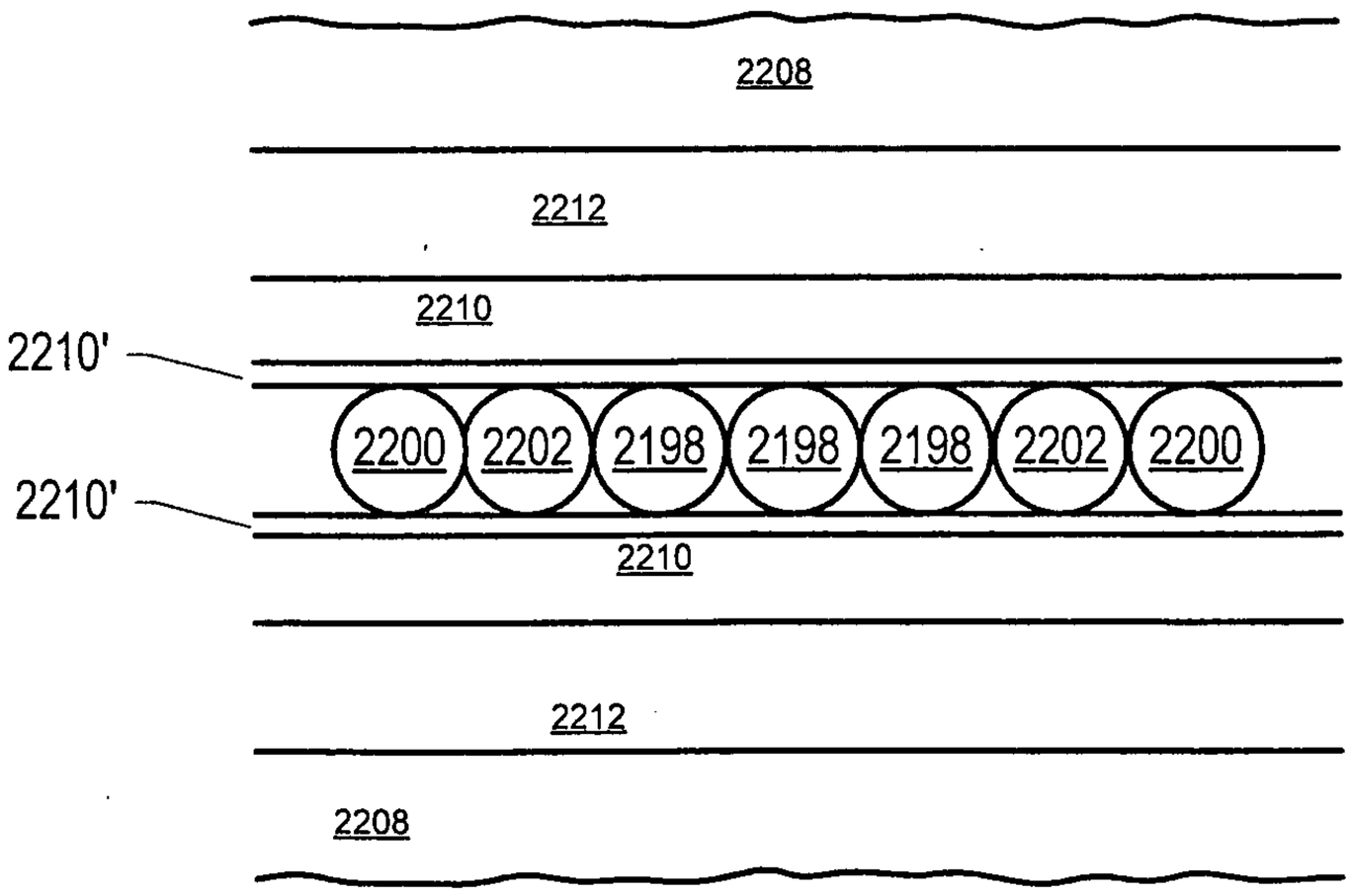


FIG. 176

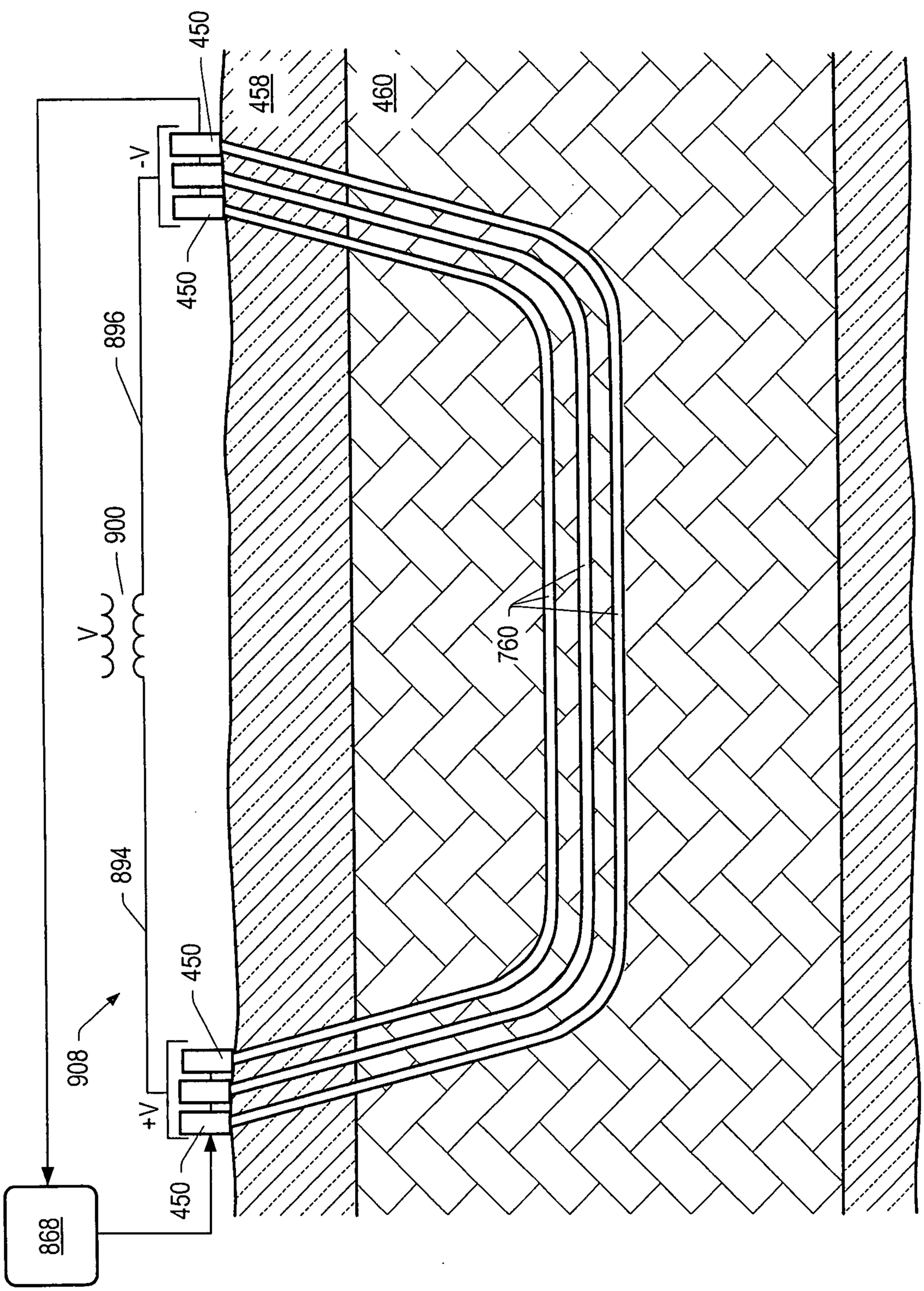


FIG. 177

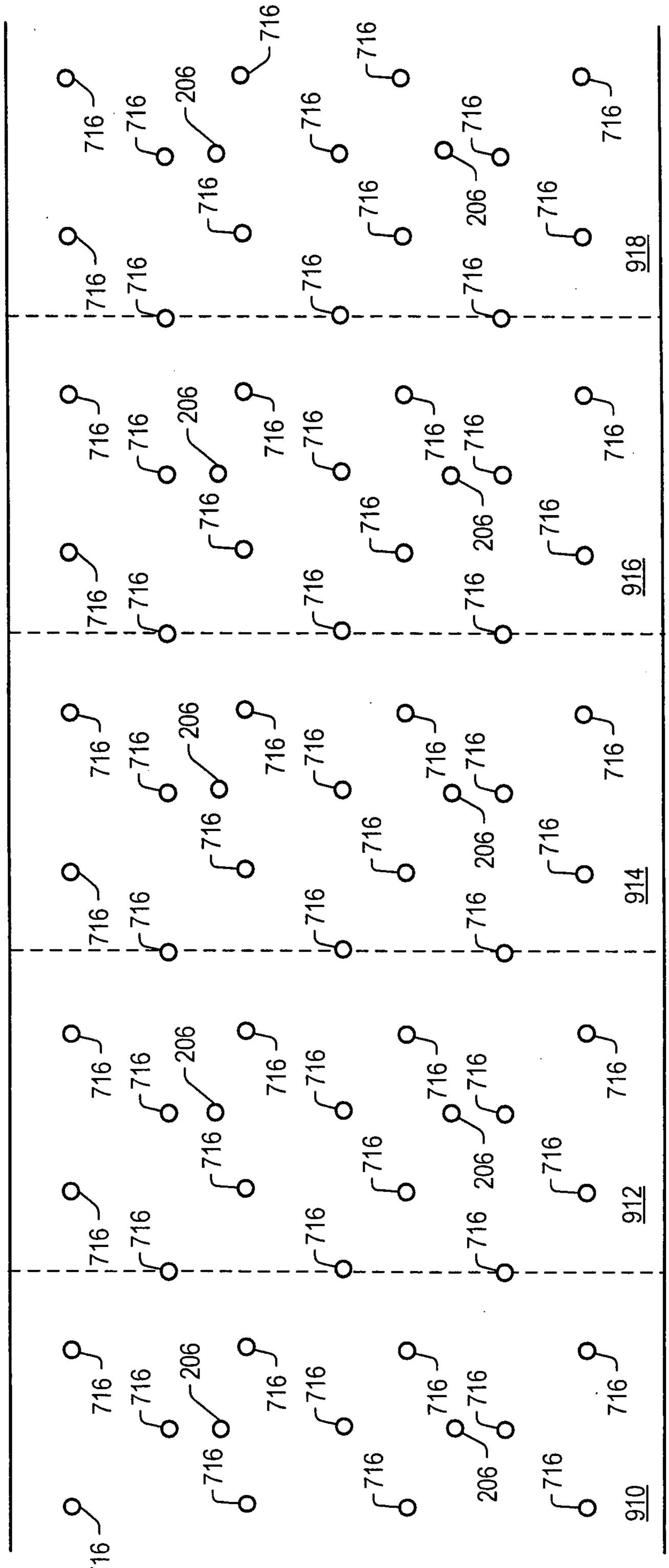


FIG. 178

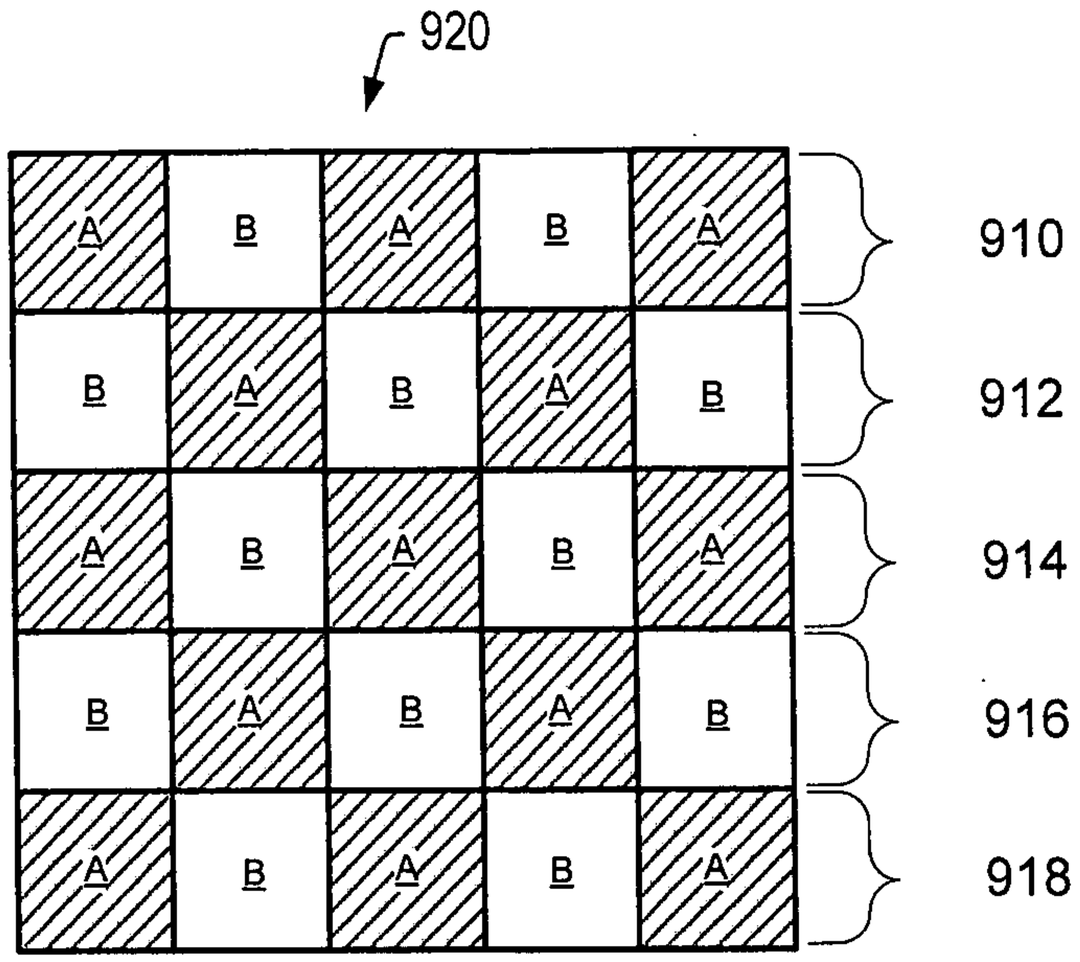


FIG. 179

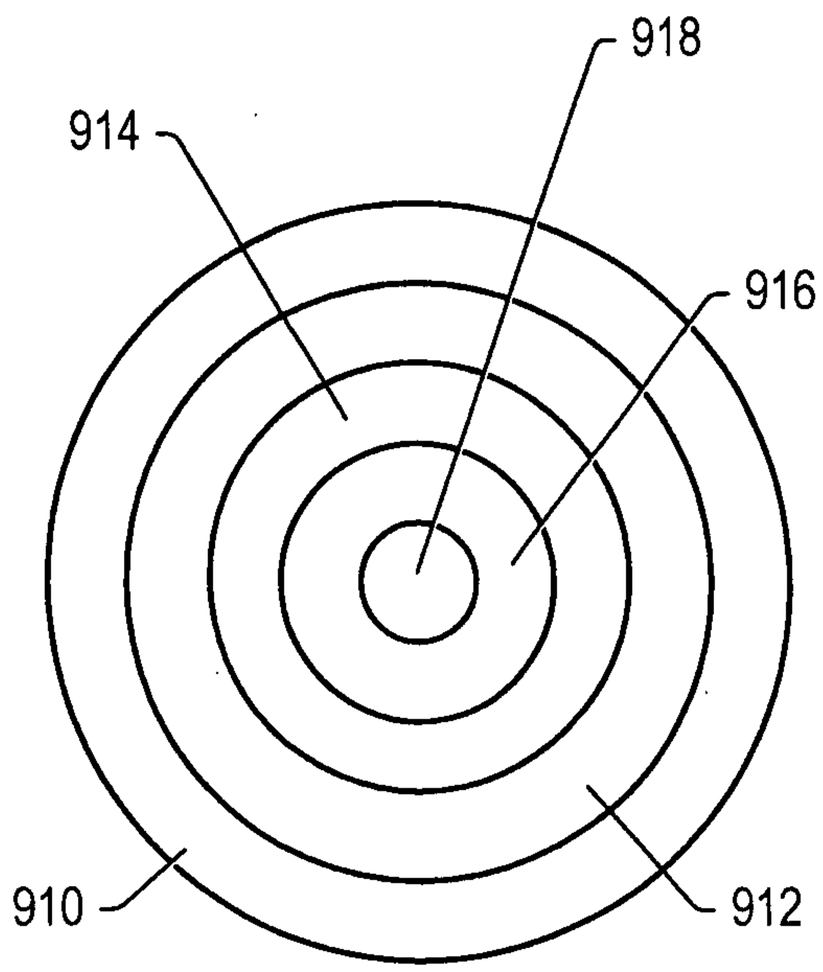


FIG. 180

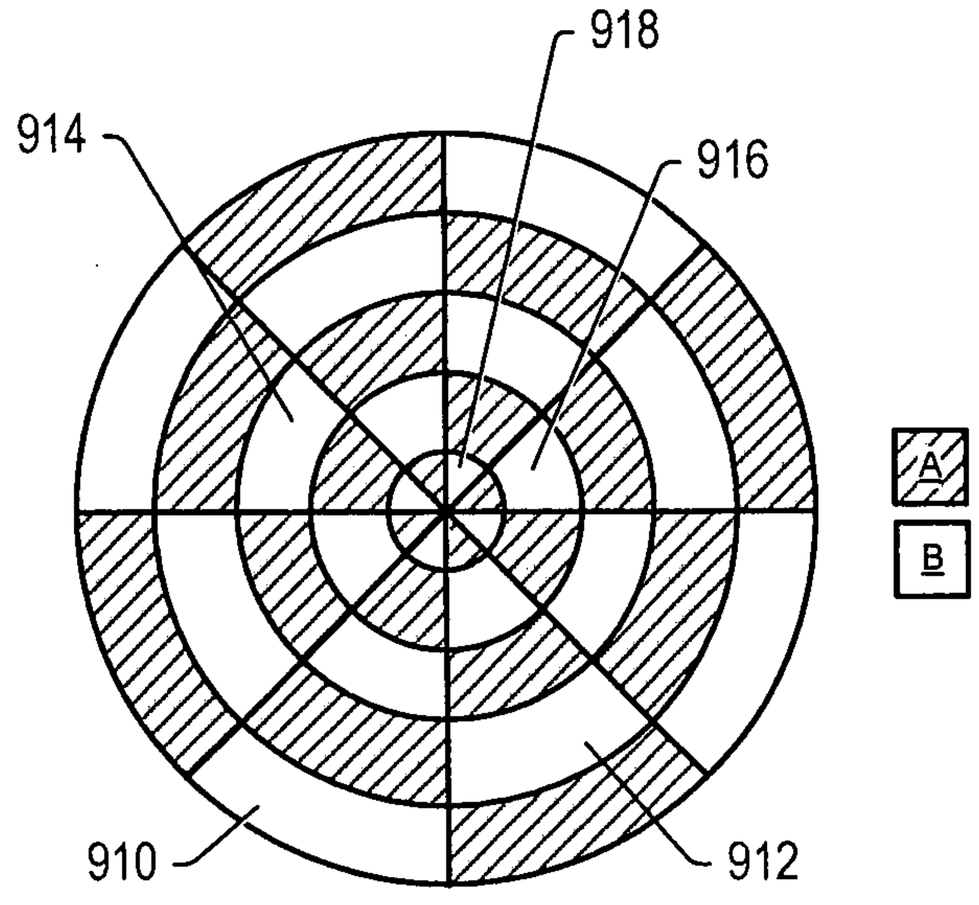


FIG. 181

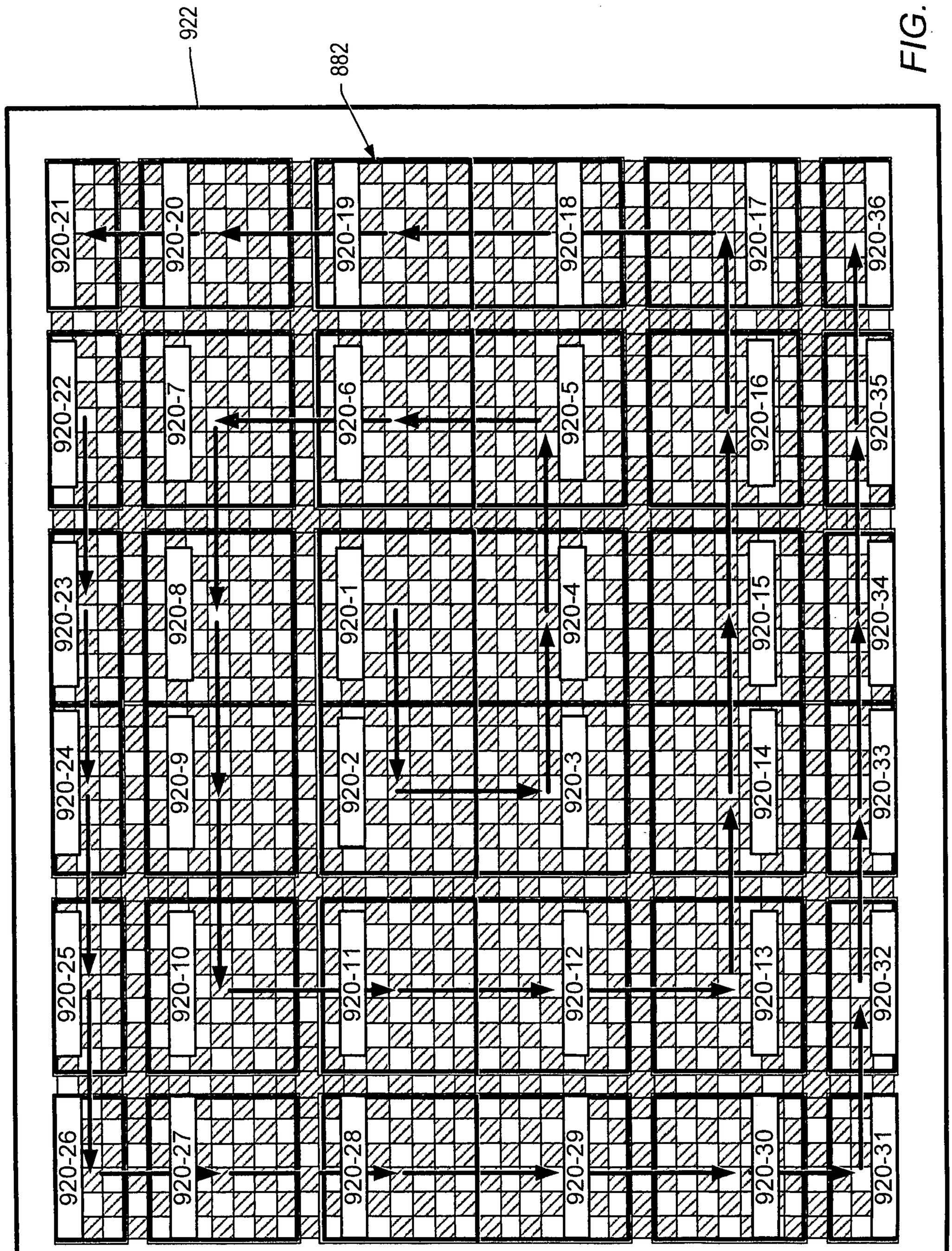

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FIG. 182

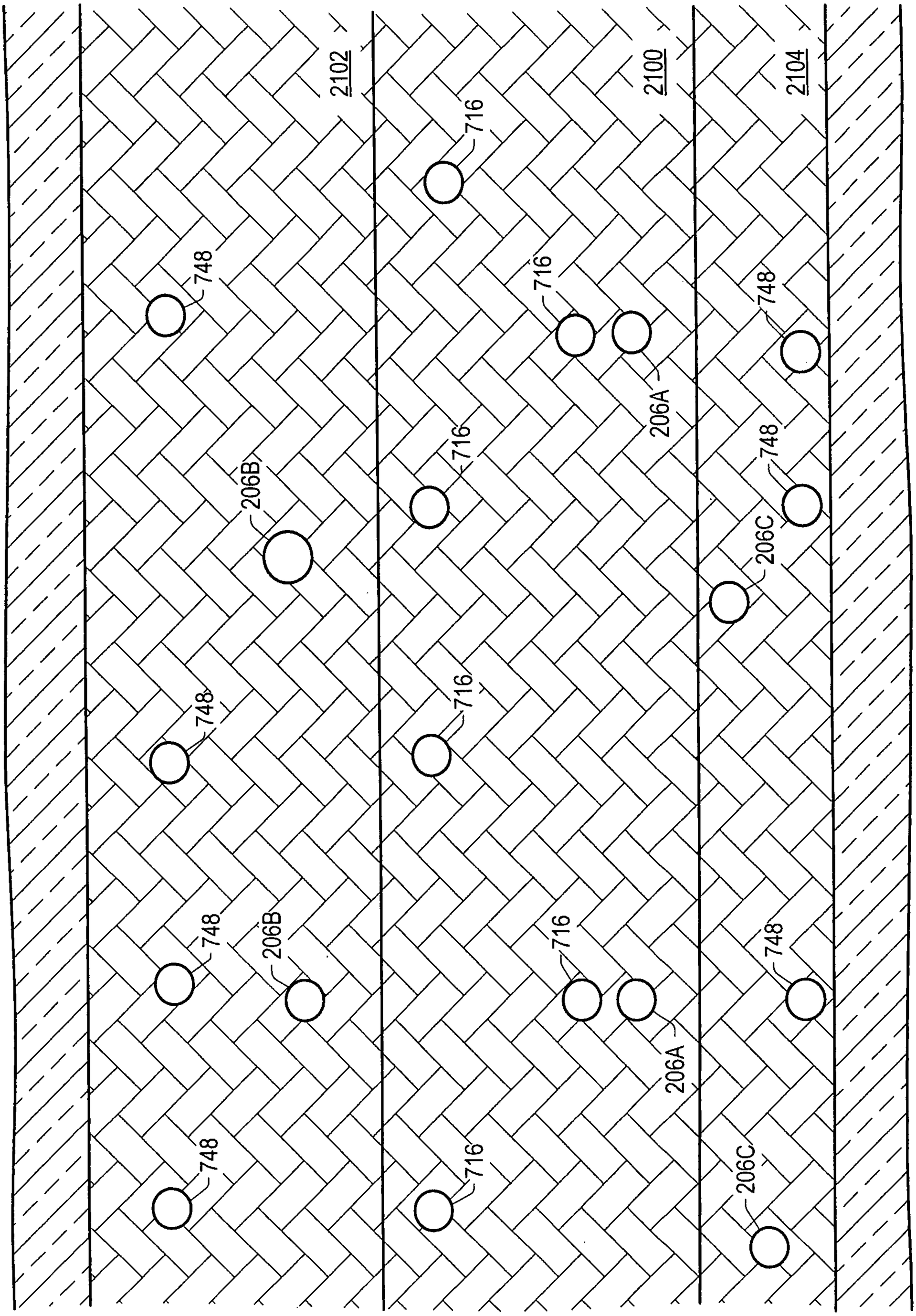


FIG. 183

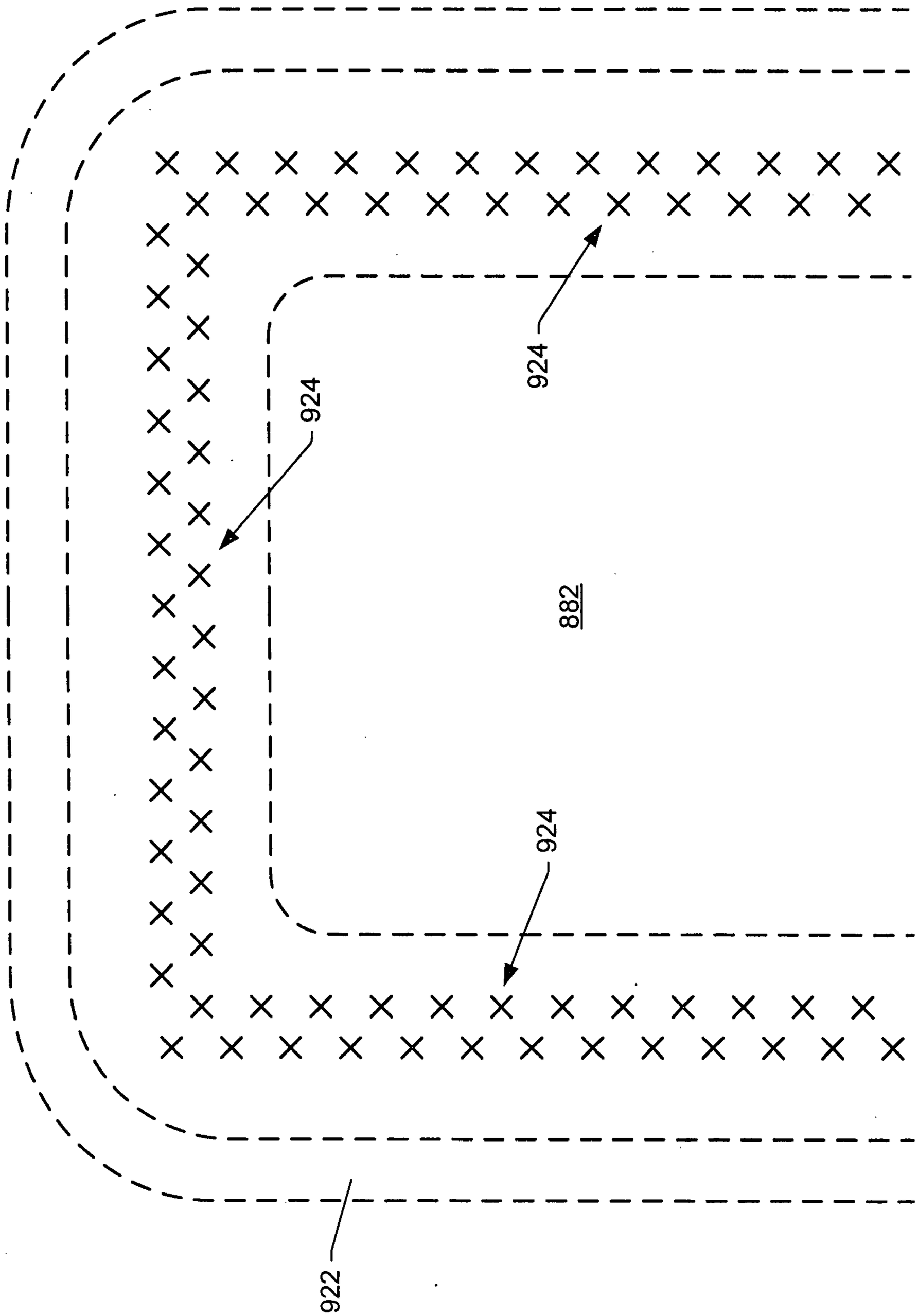


FIG. 184

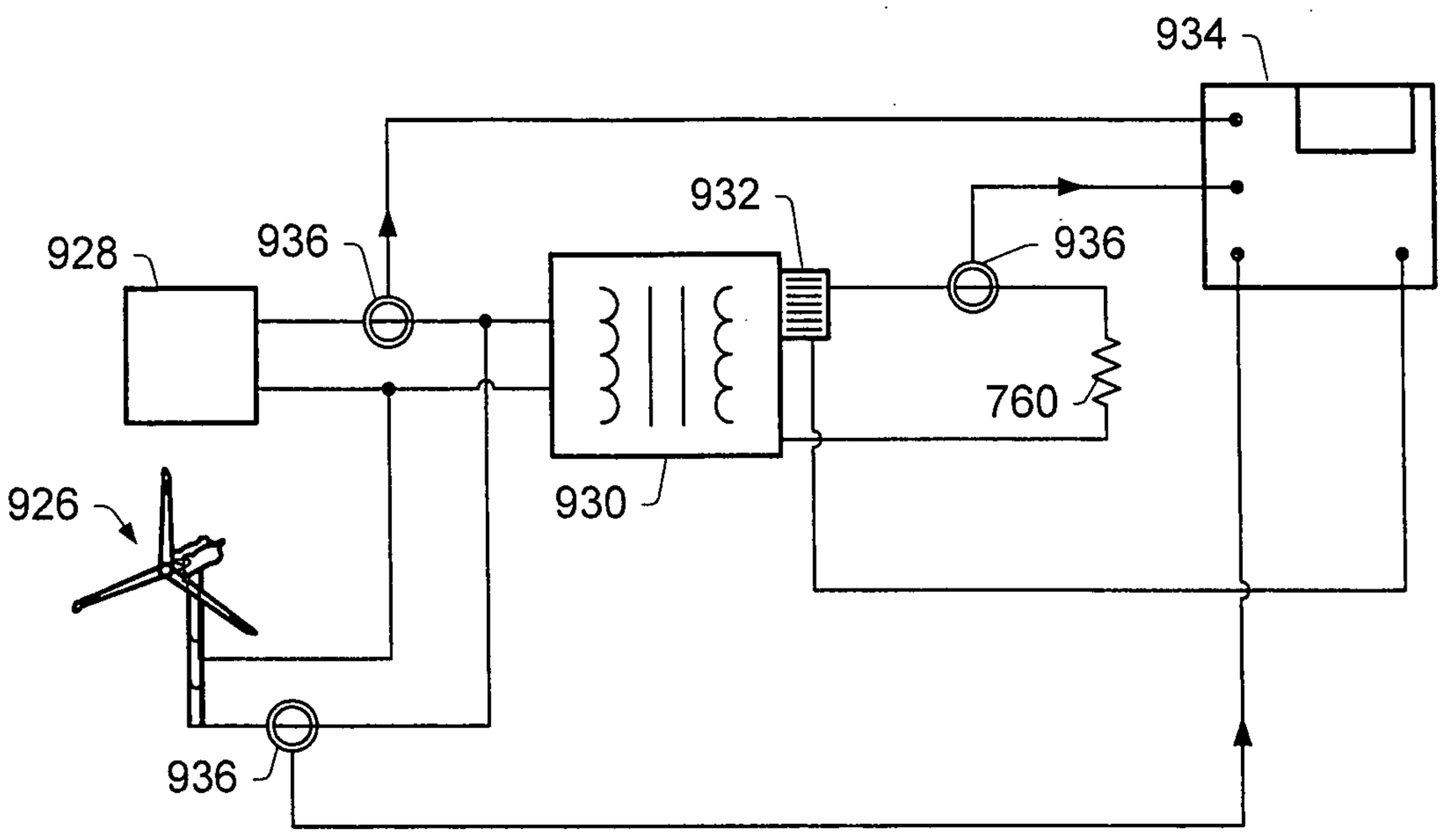


FIG. 185

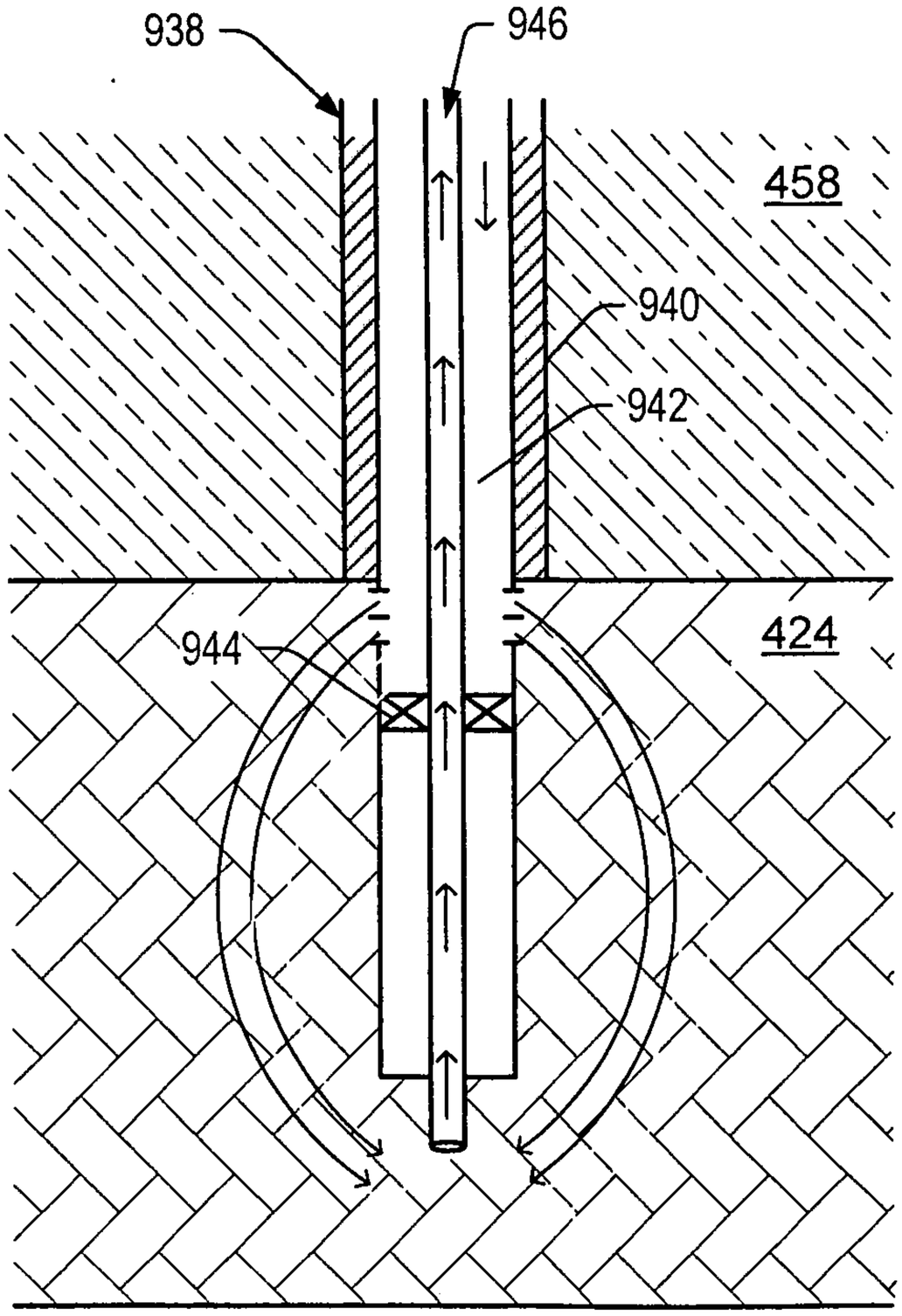


FIG. 186

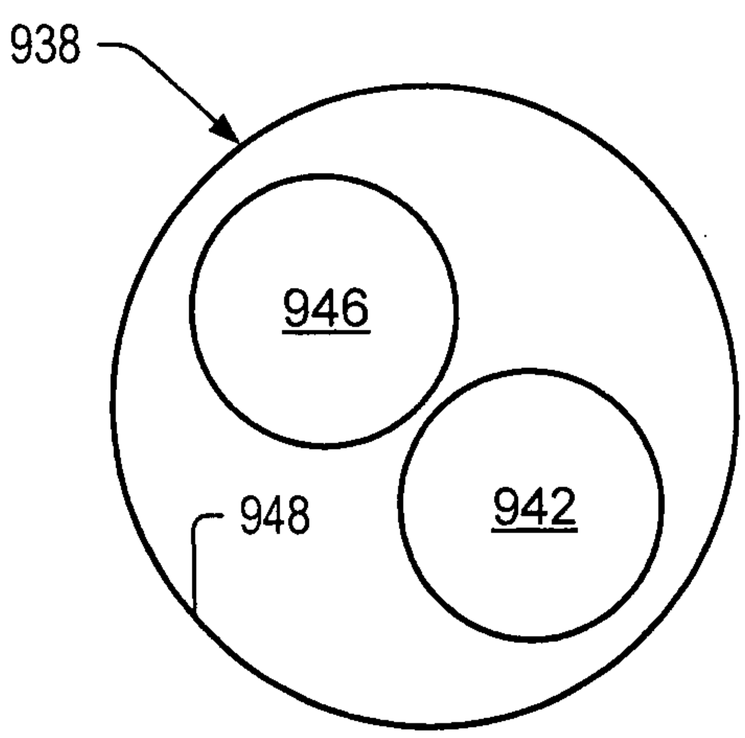


FIG. 187

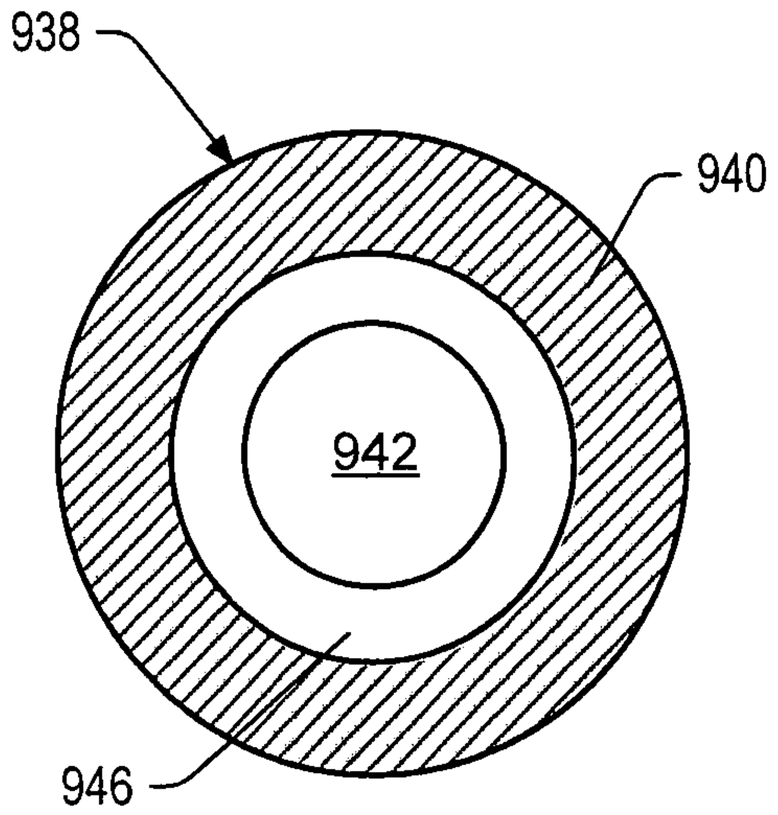


FIG. 188

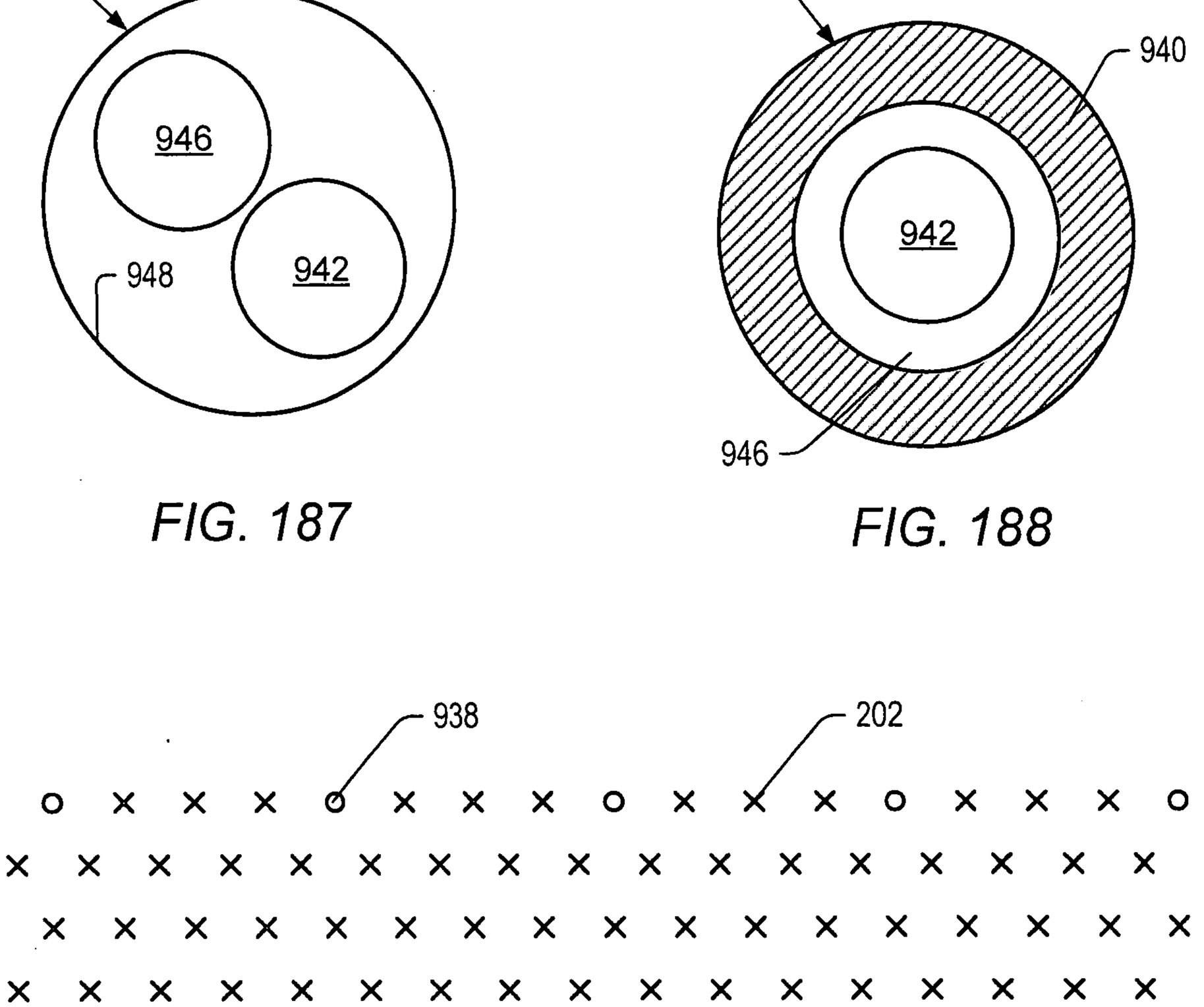


FIG. 189

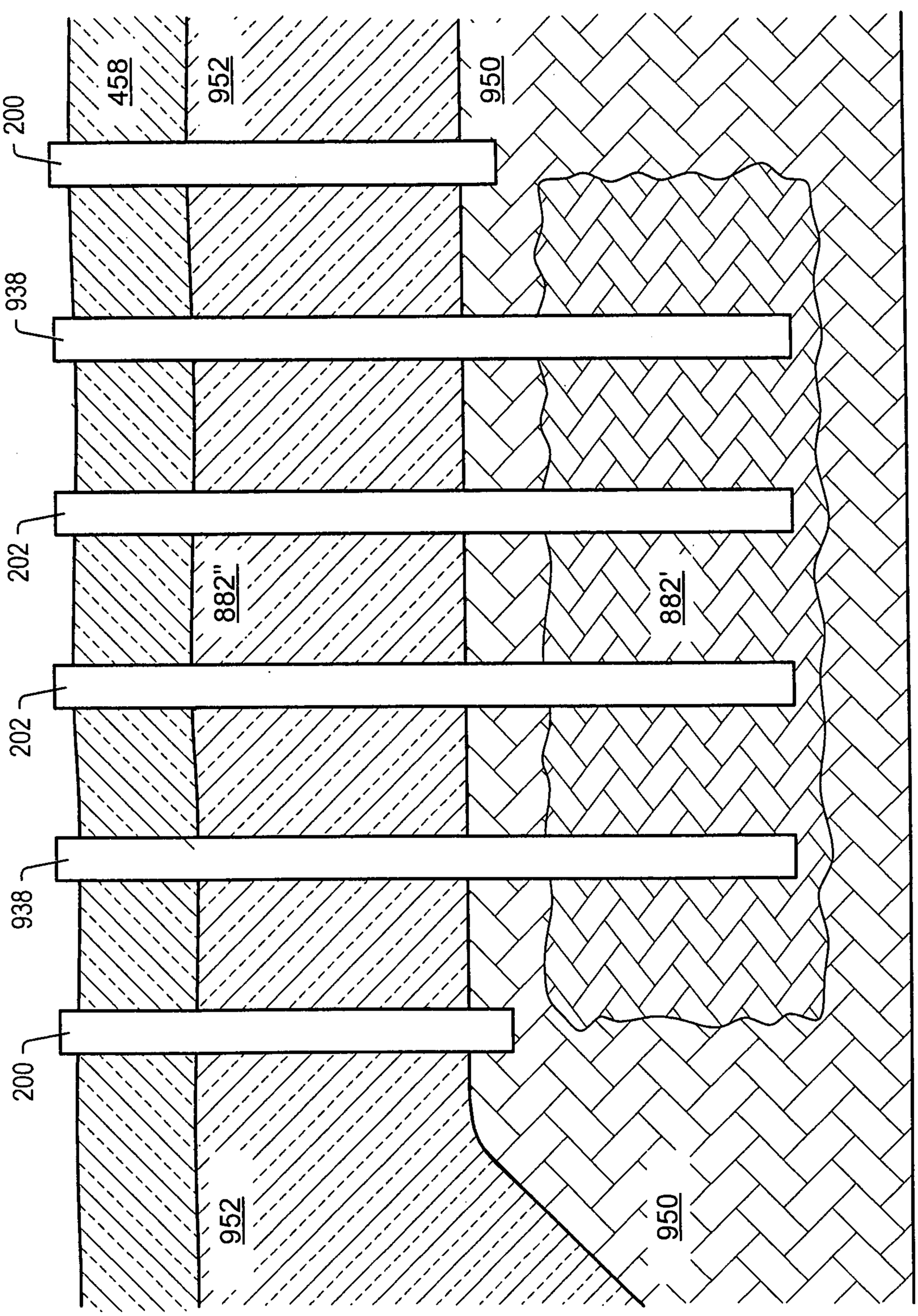


FIG. 190

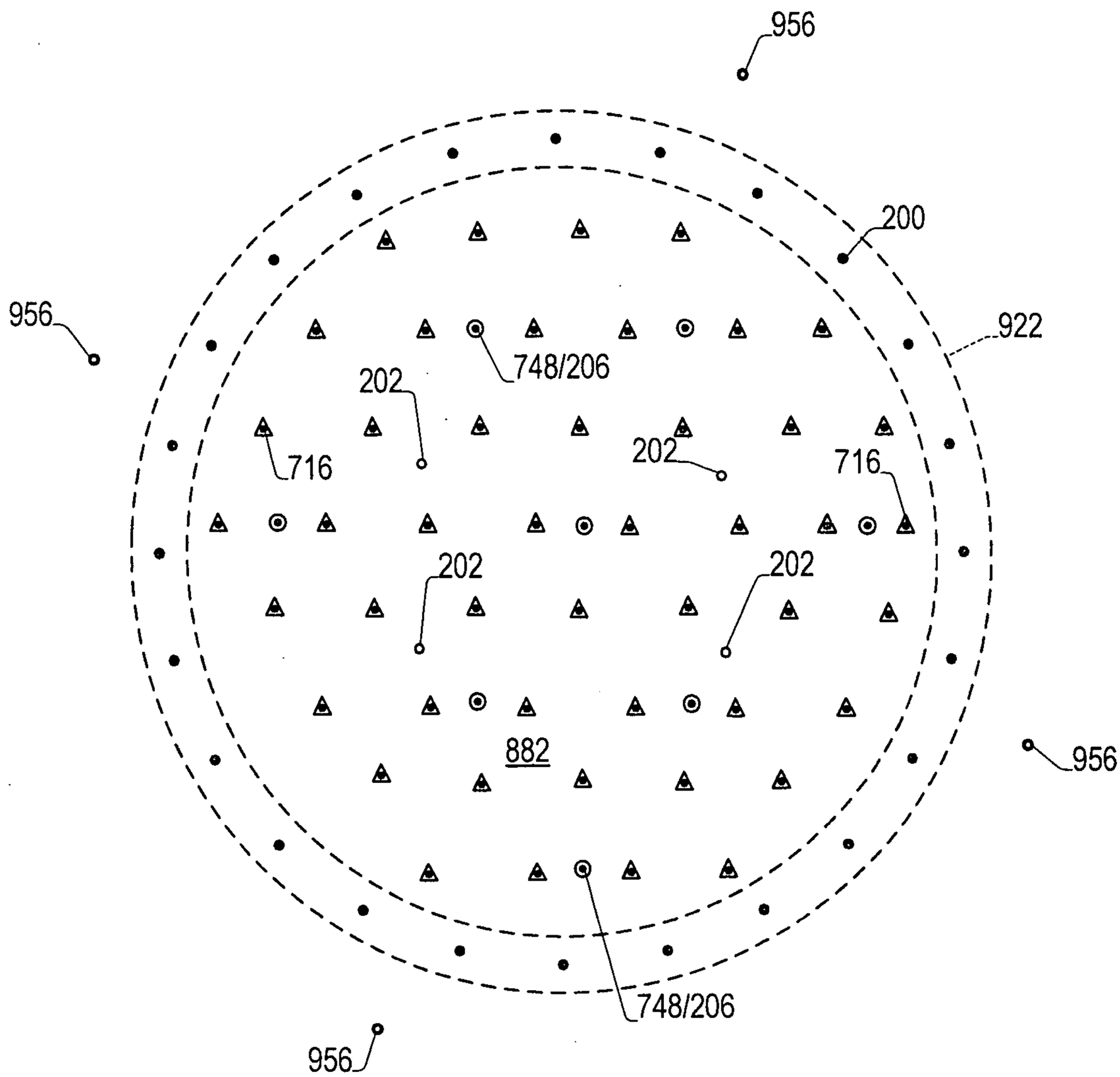

956
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FIG. 191

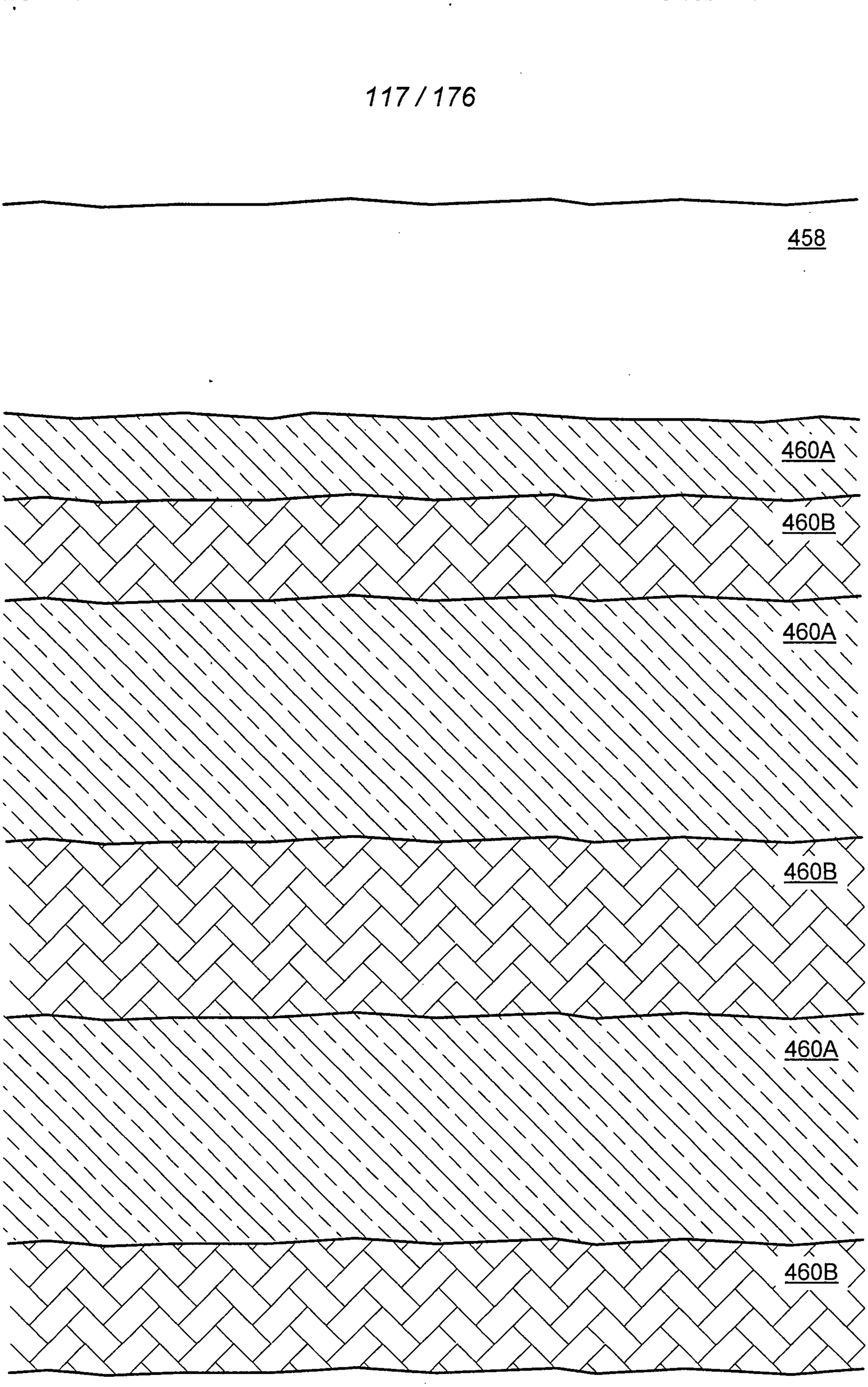


FIG. 192

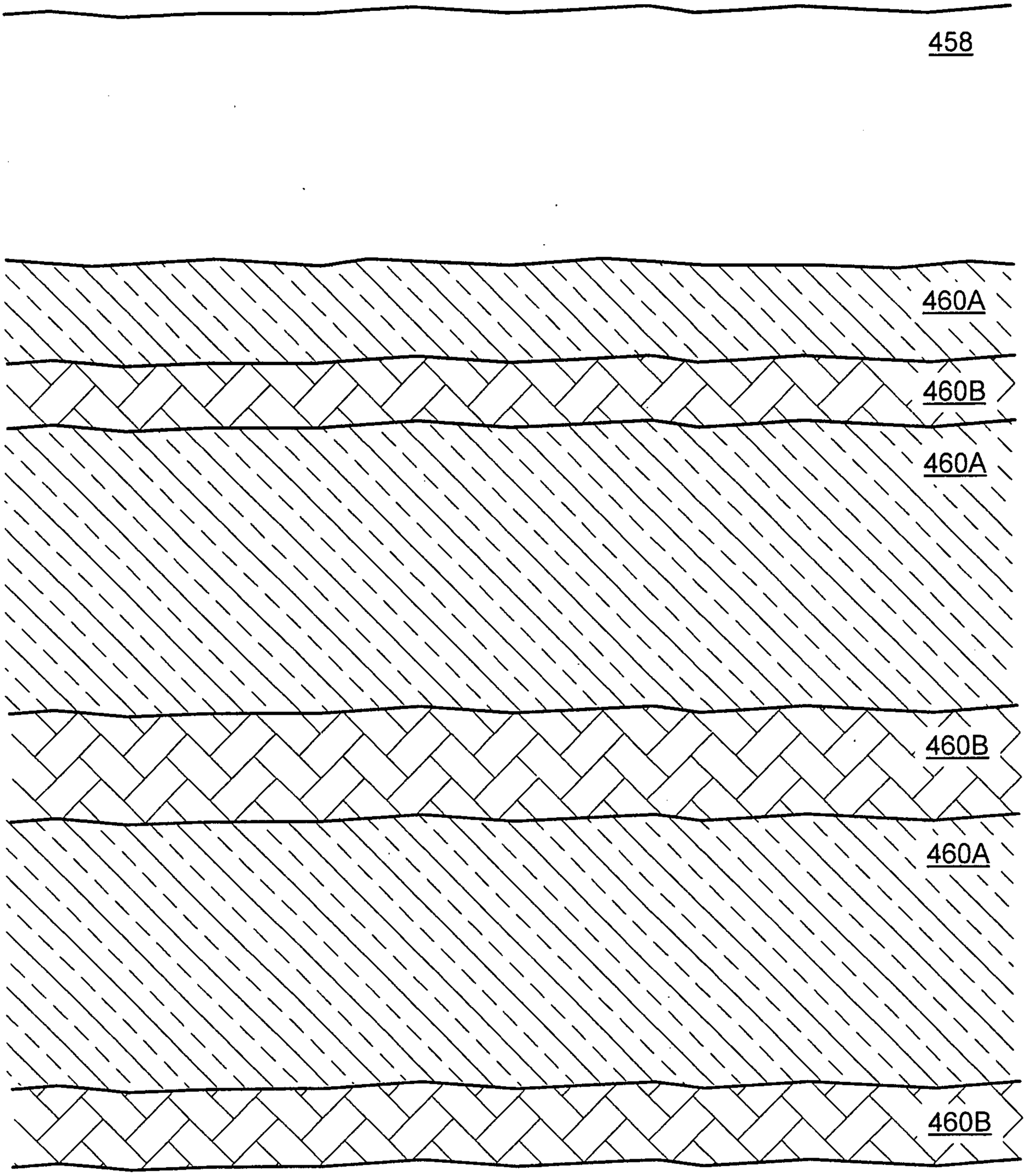


FIG. 193

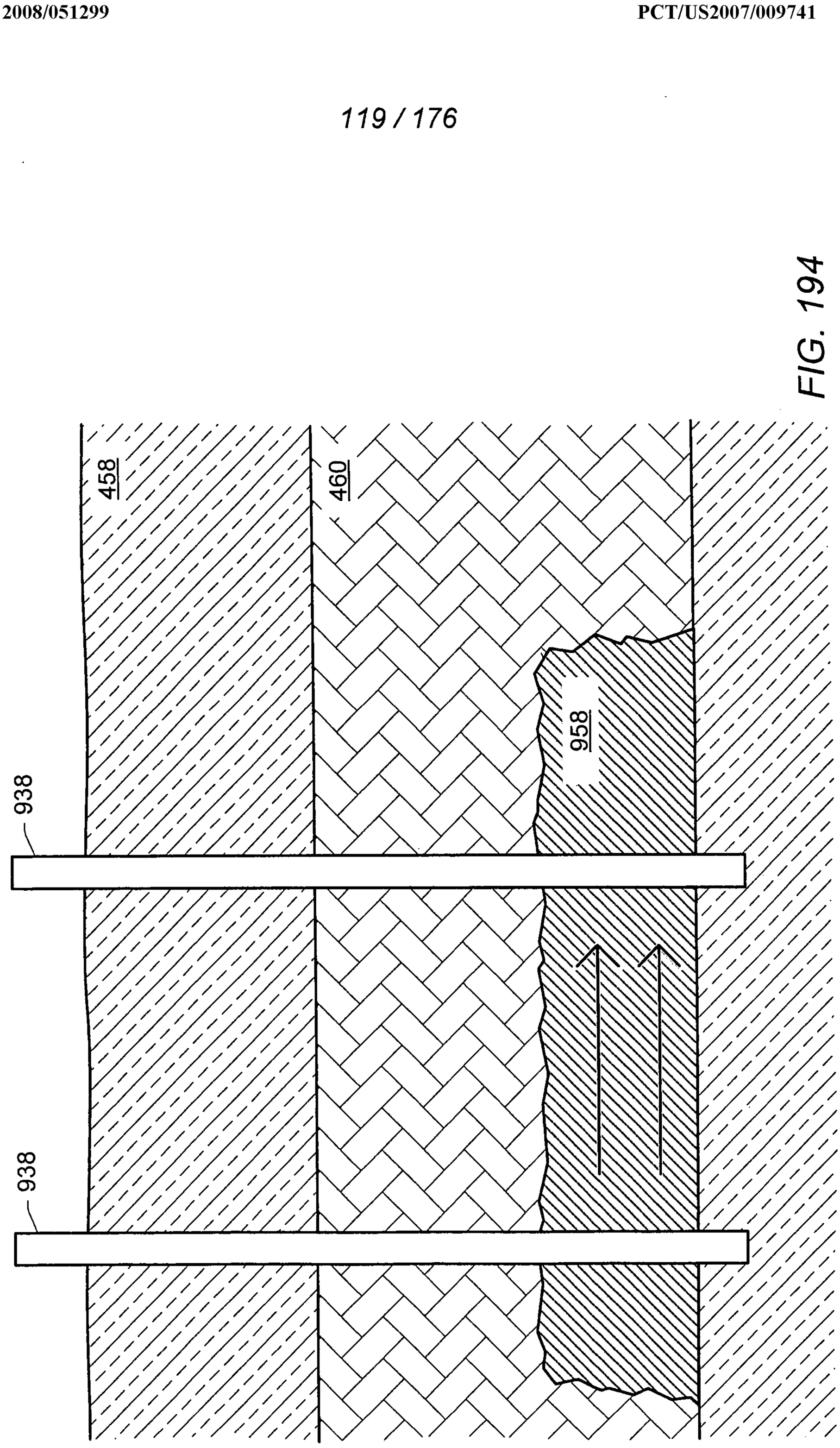


FIG. 194

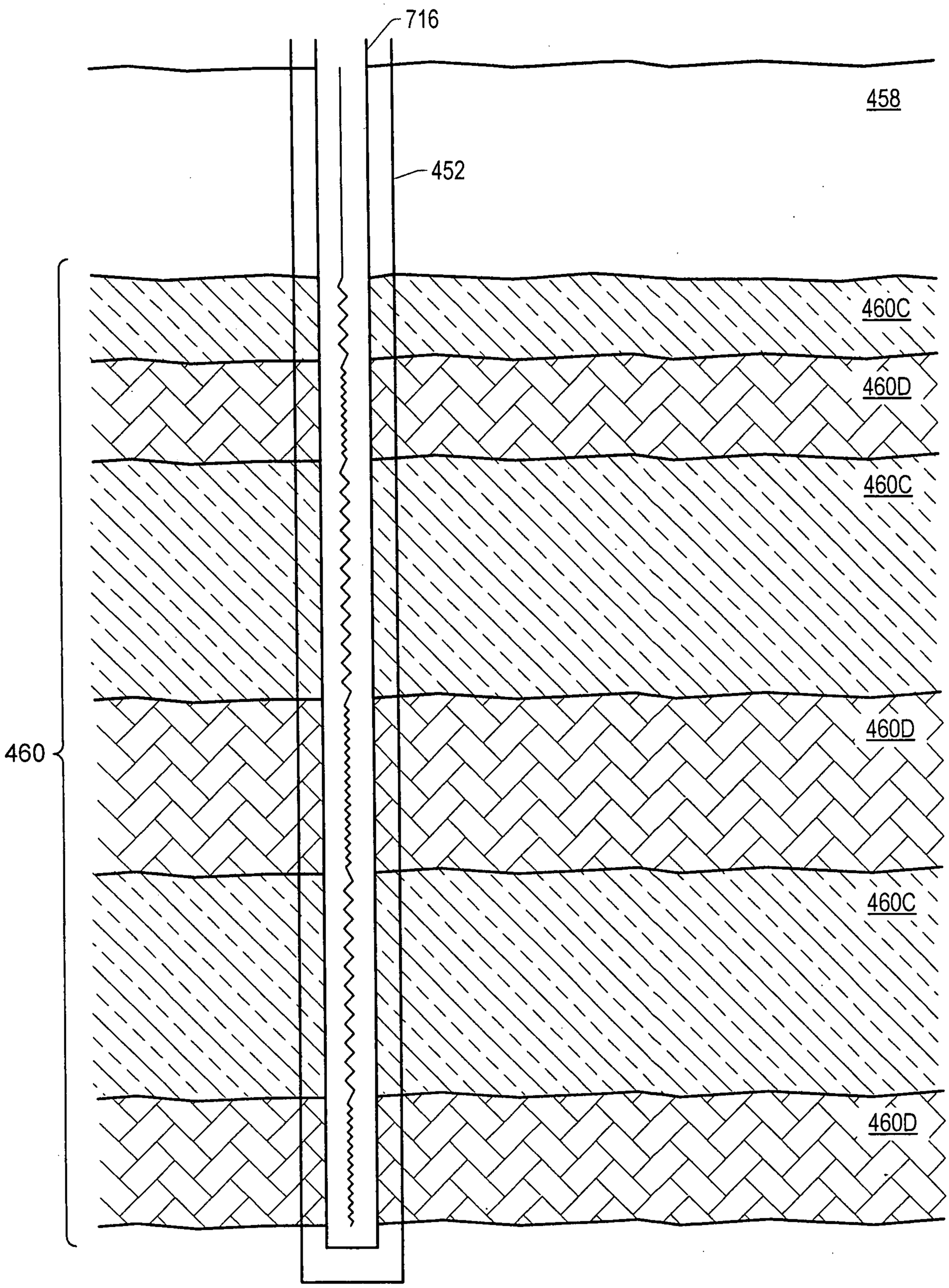


FIG. 195

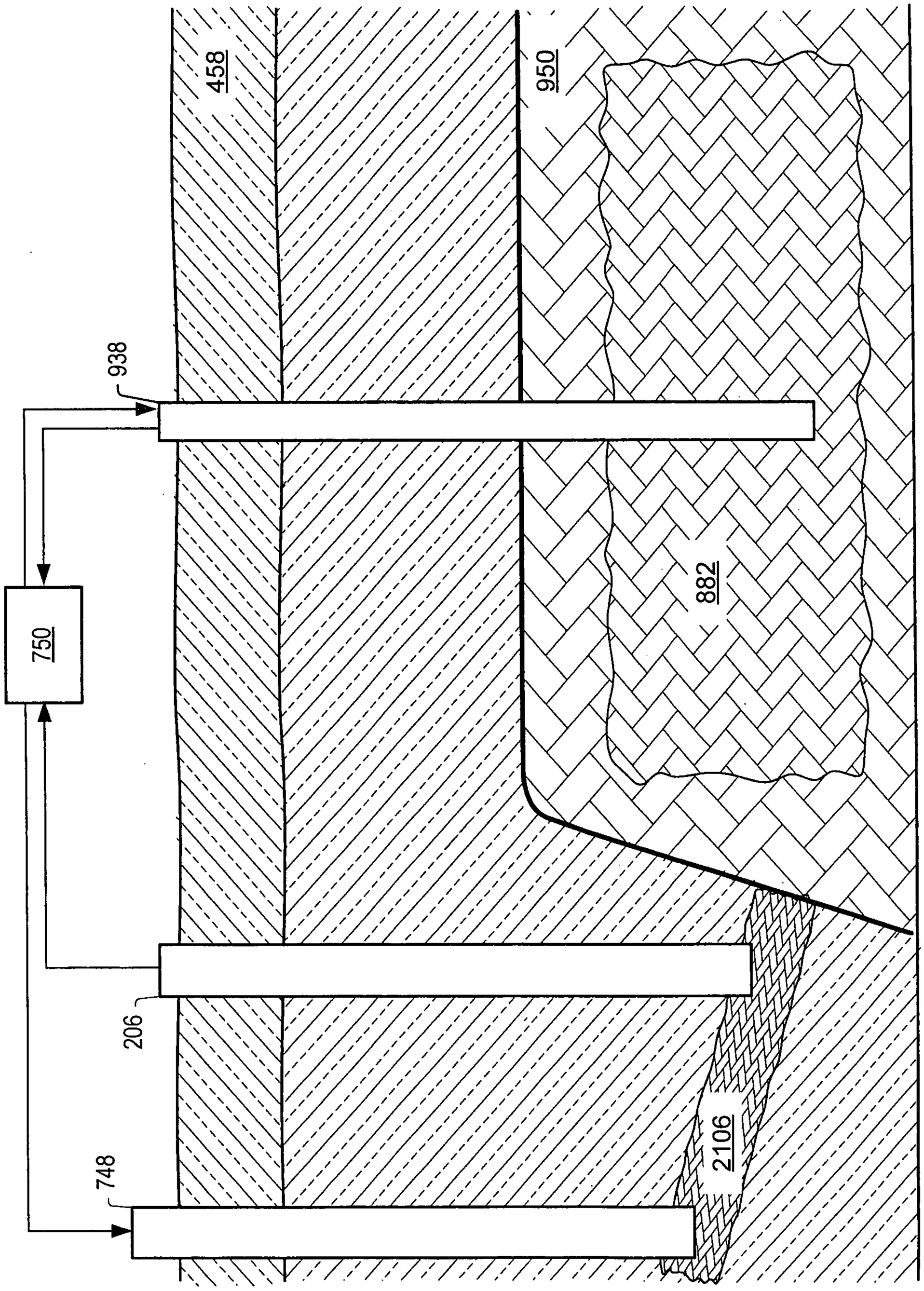


FIG. 196

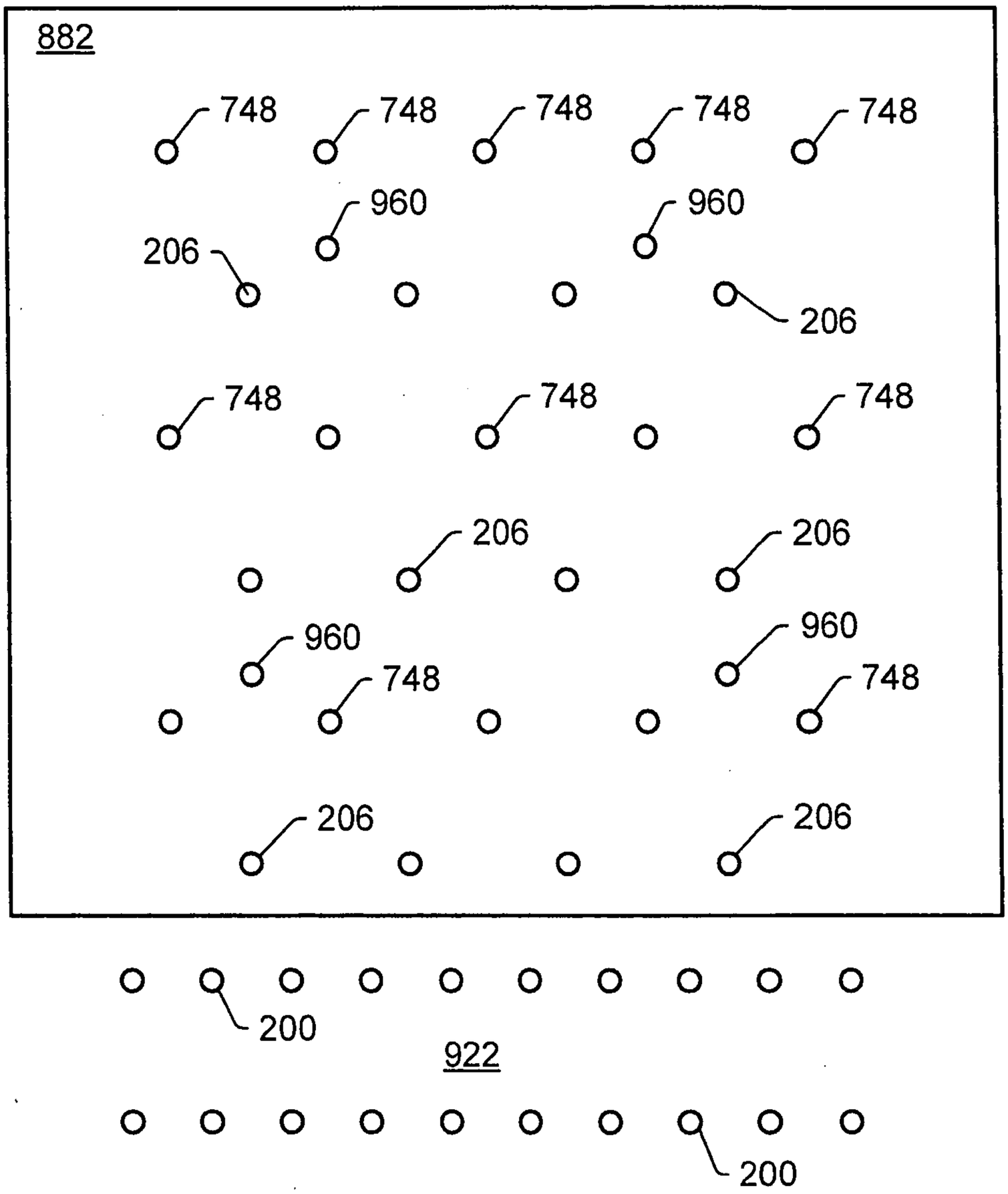

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FIG. 197

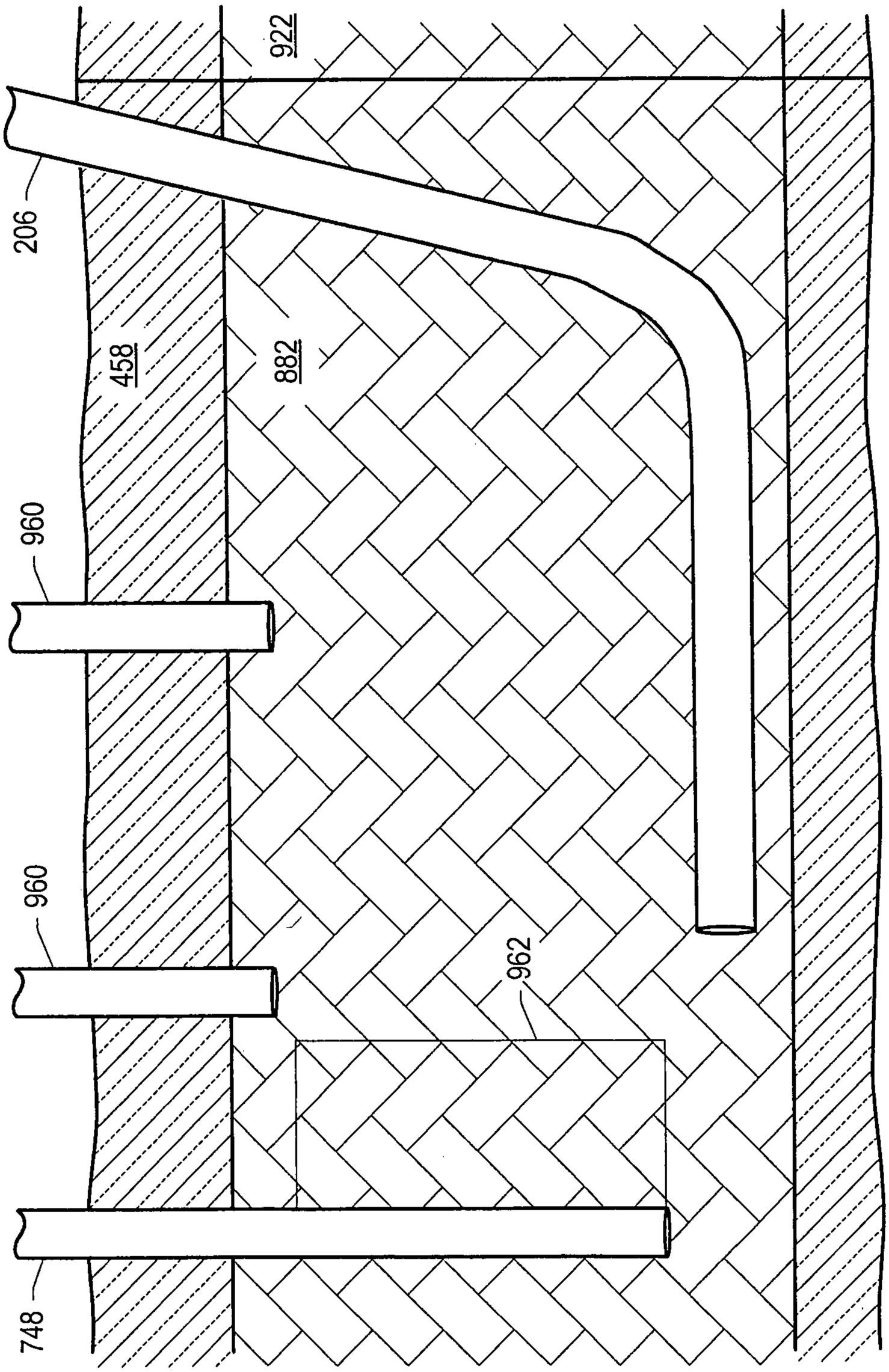


FIG. 198

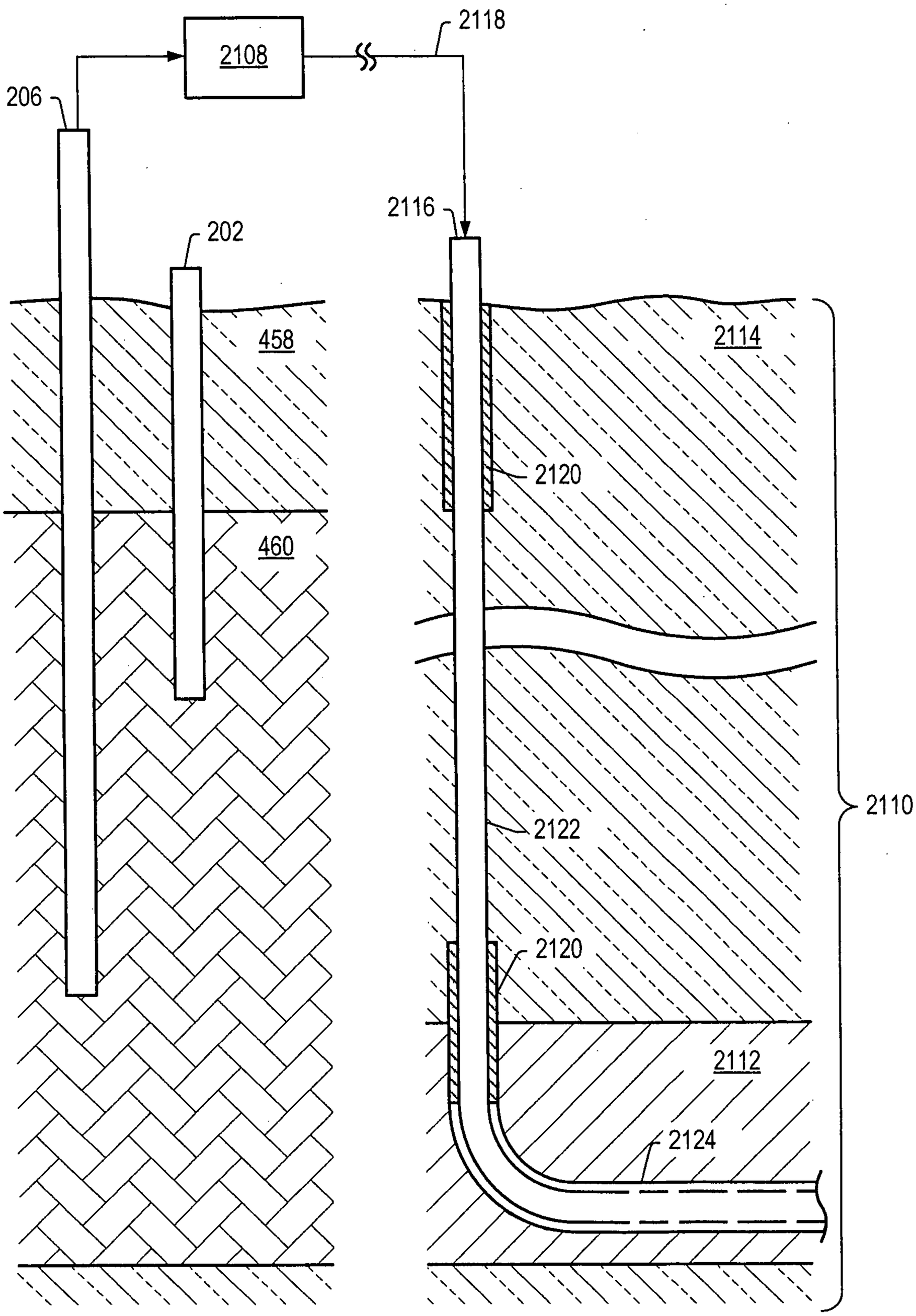

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FIG. 199

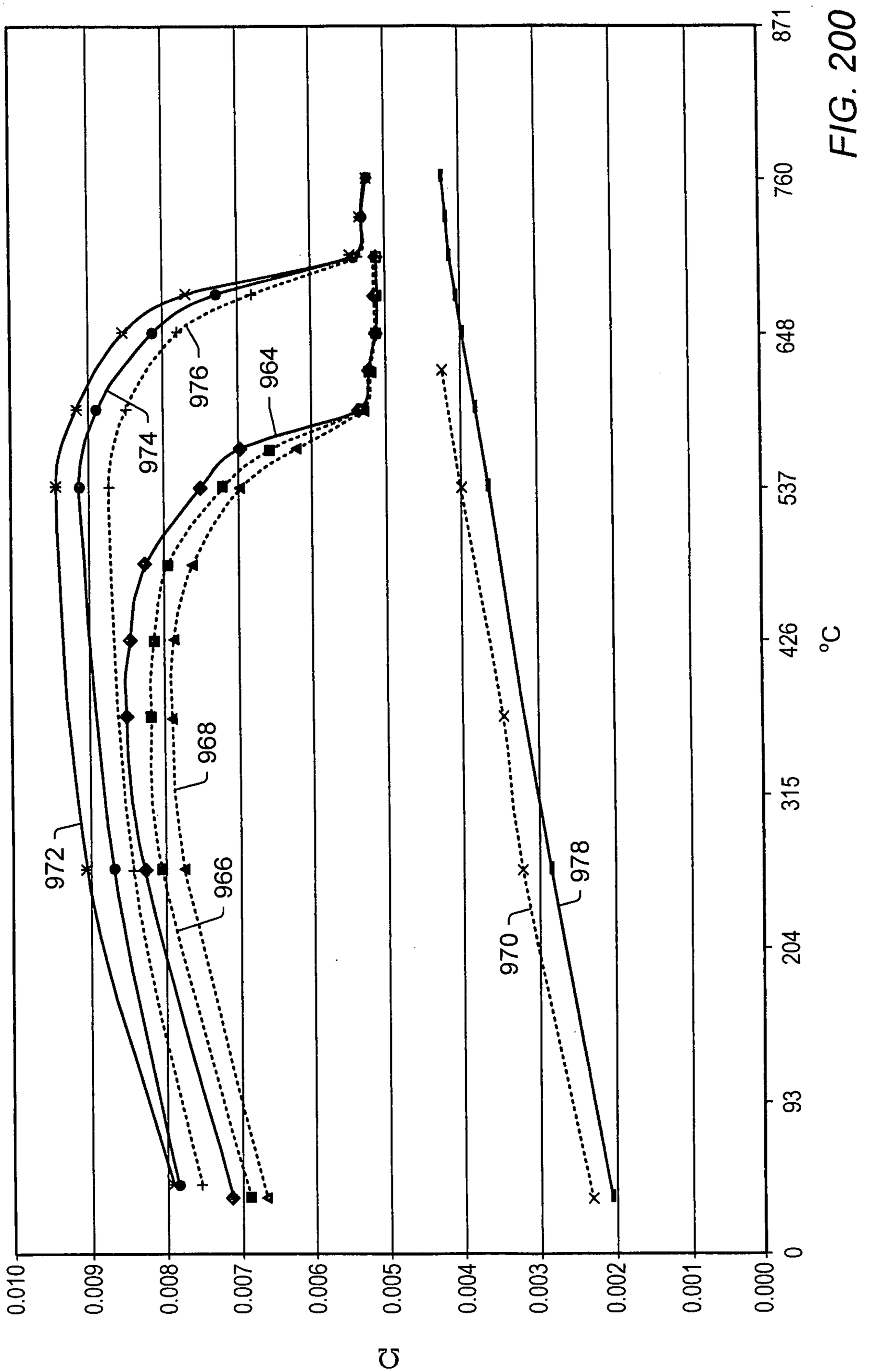

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FIG. 200

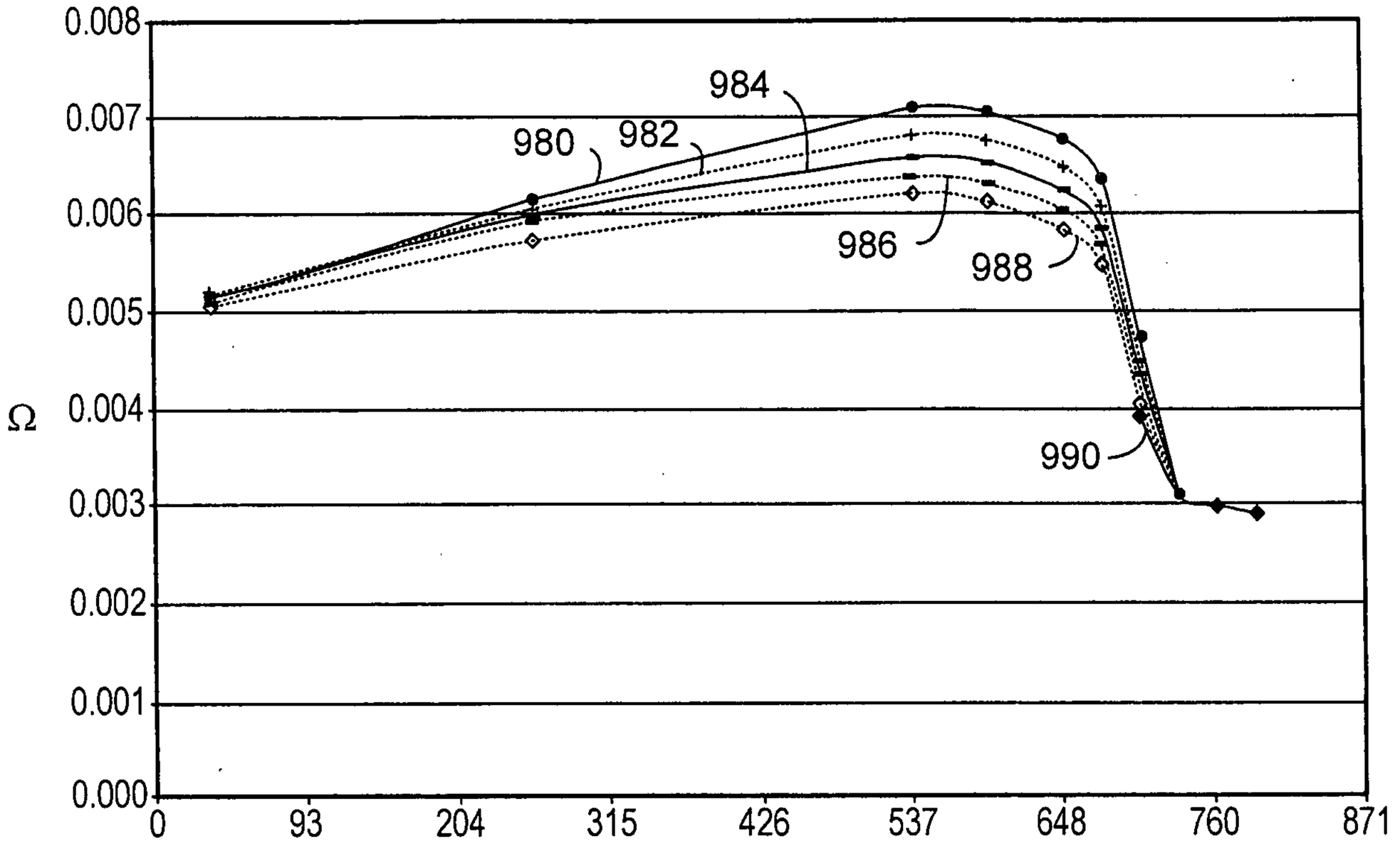


FIG. 201

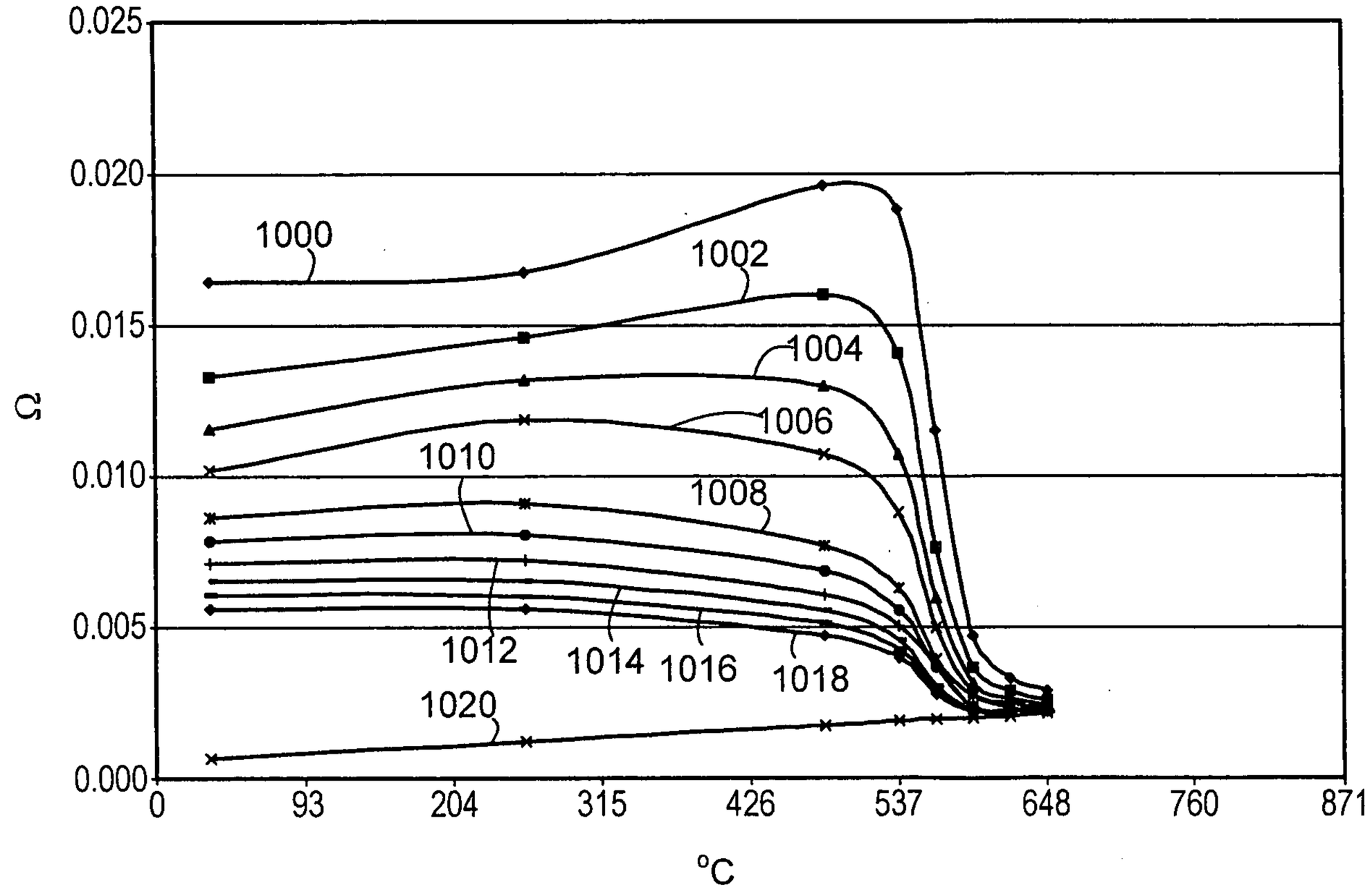


FIG. 202

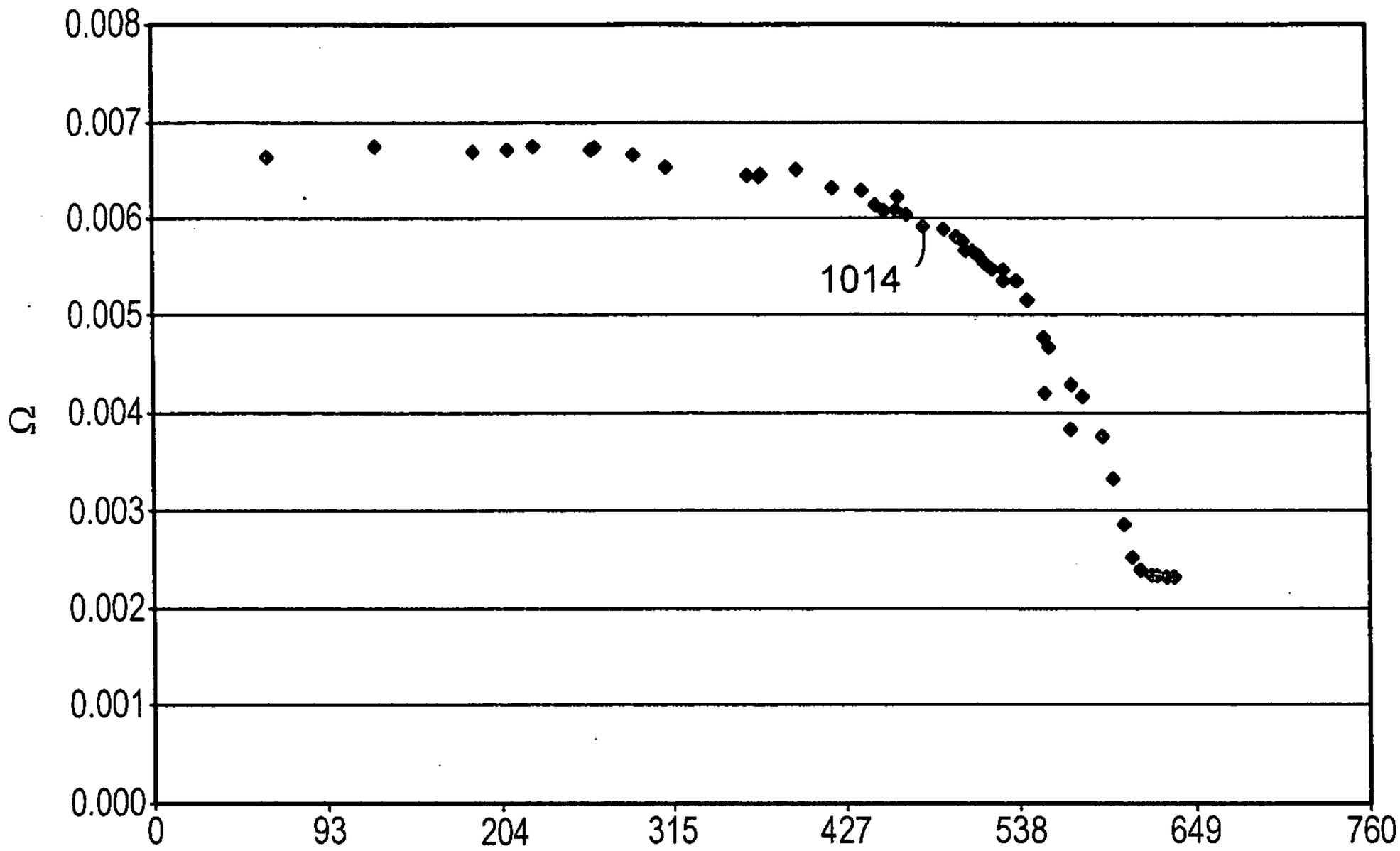


FIG. 203

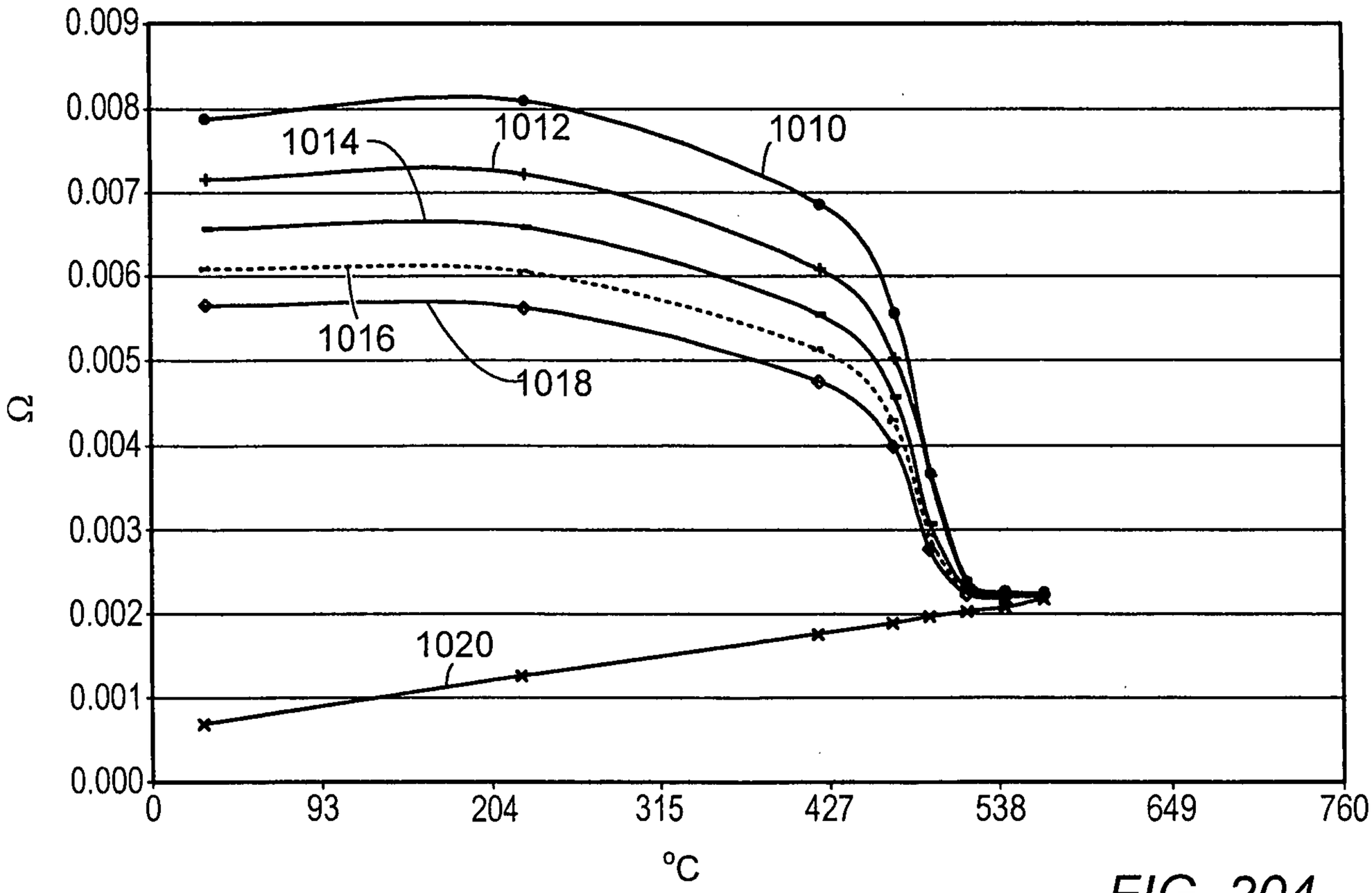


FIG. 204

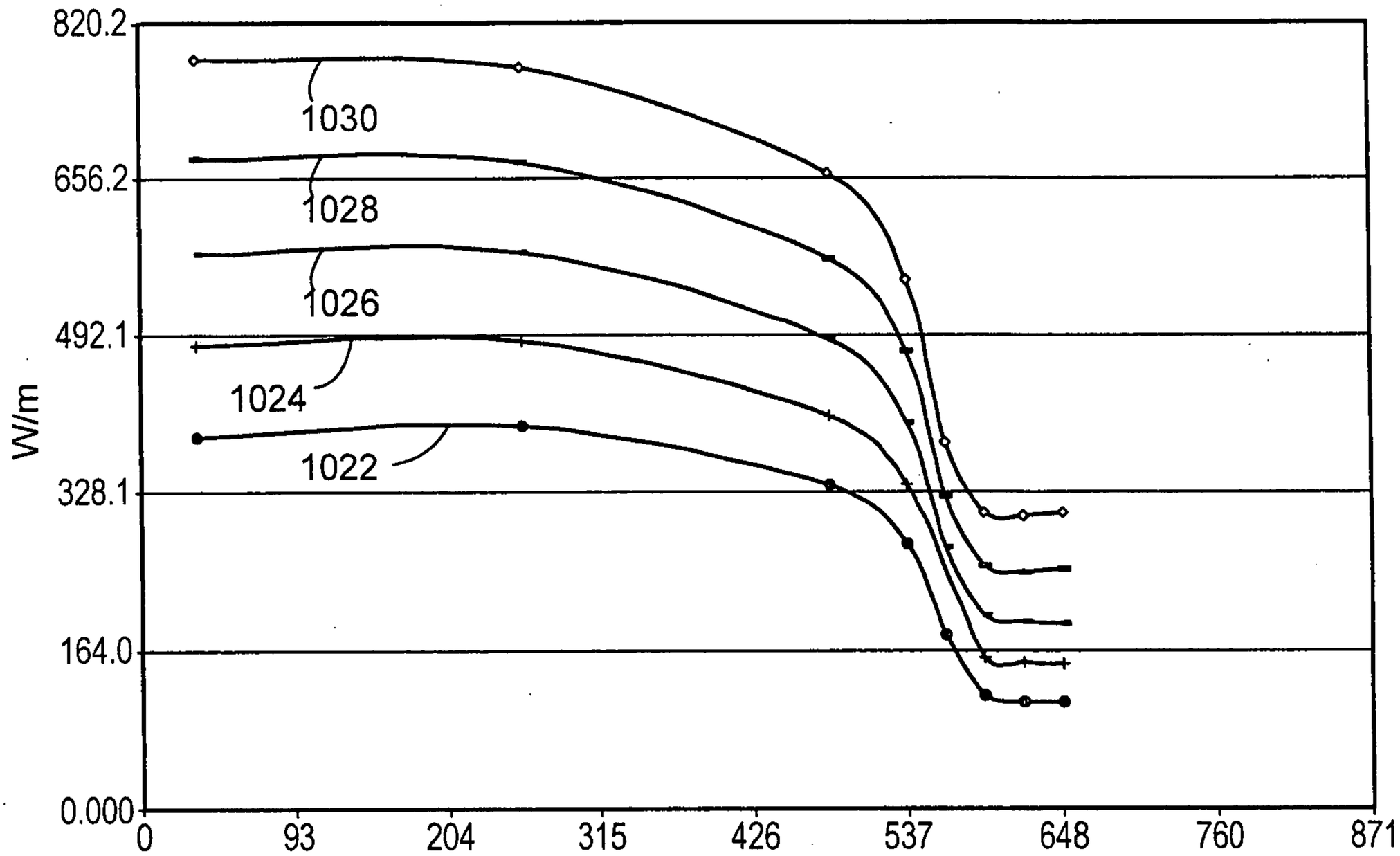


FIG. 205

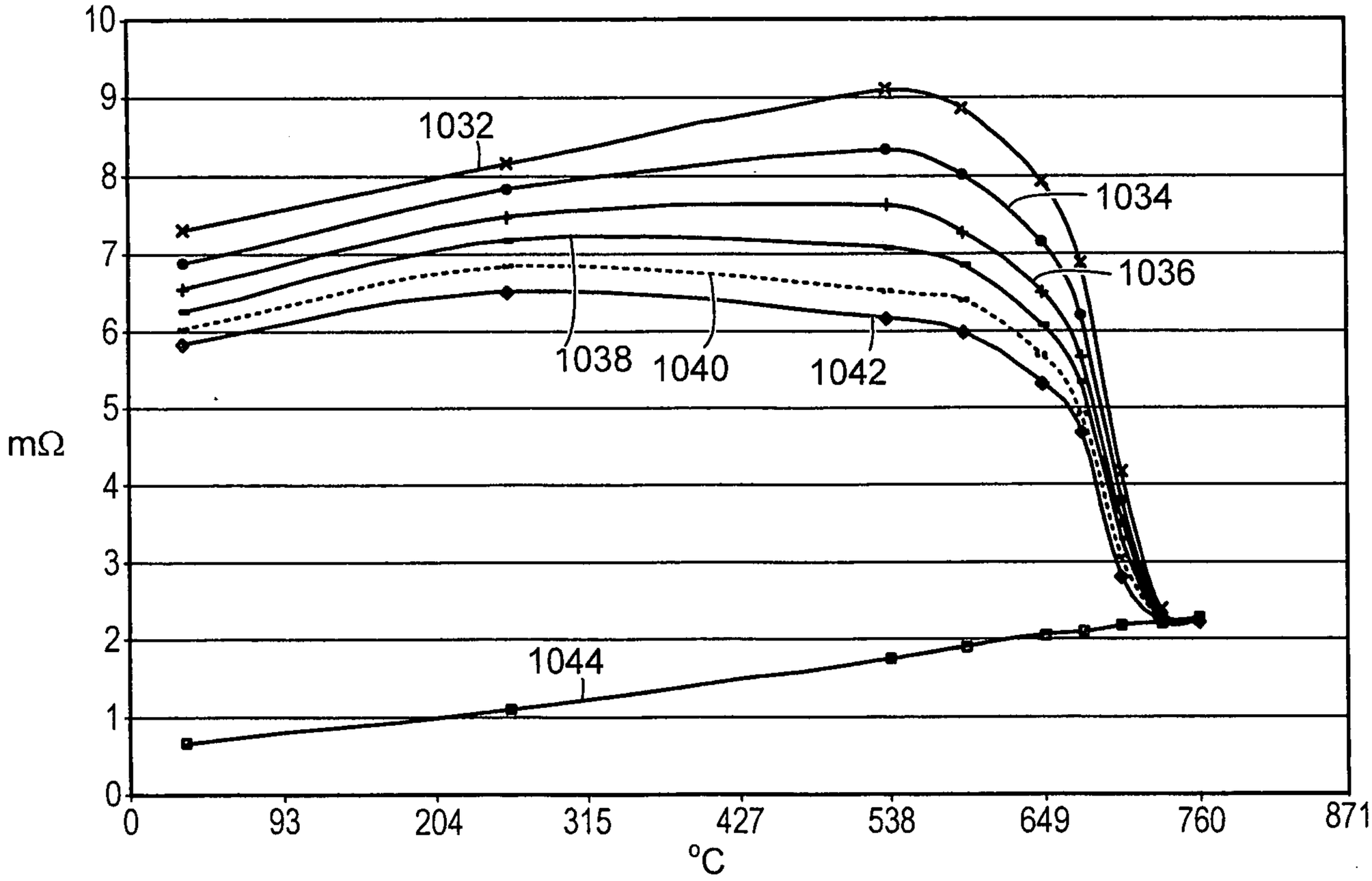


FIG. 206

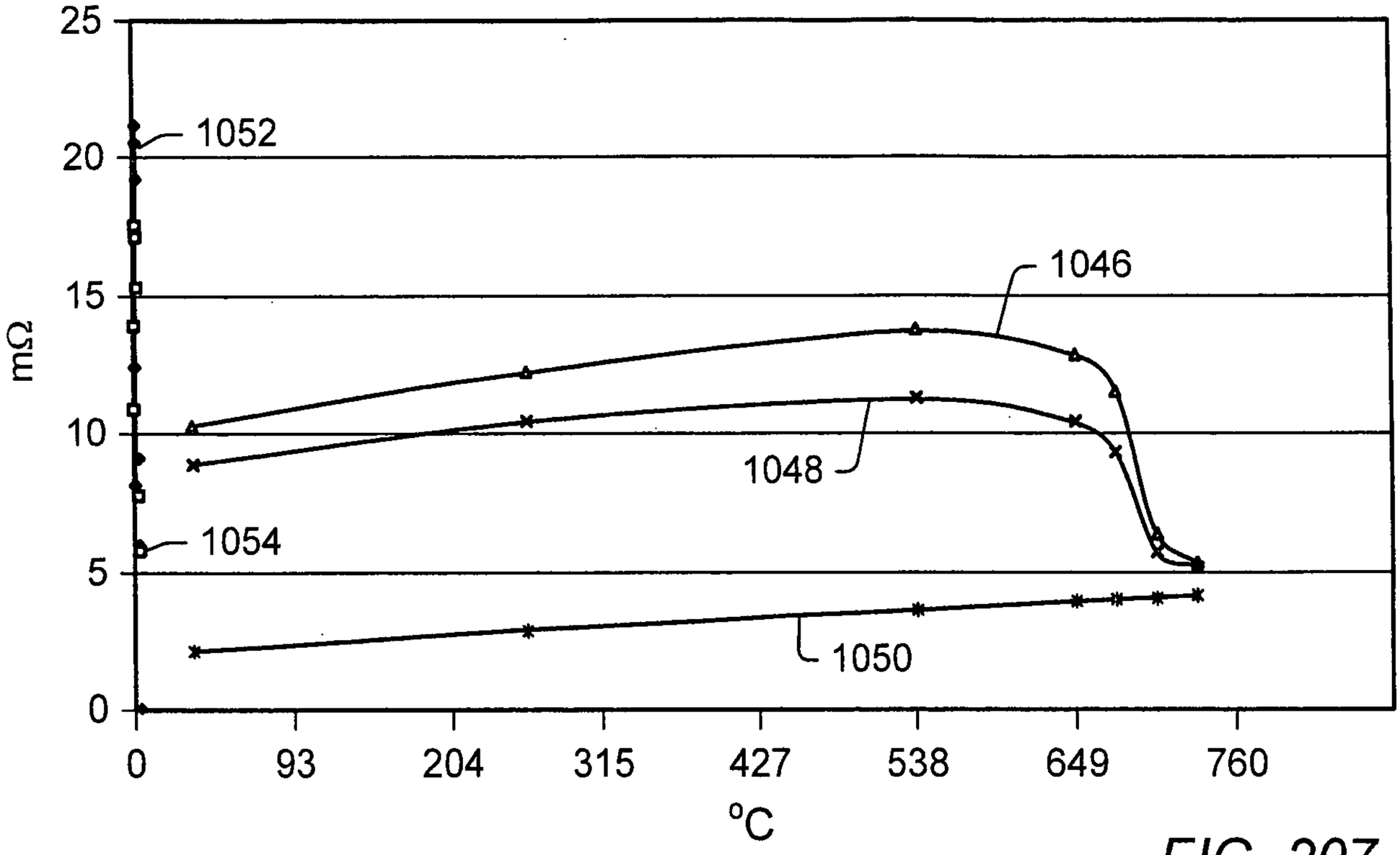


FIG. 207

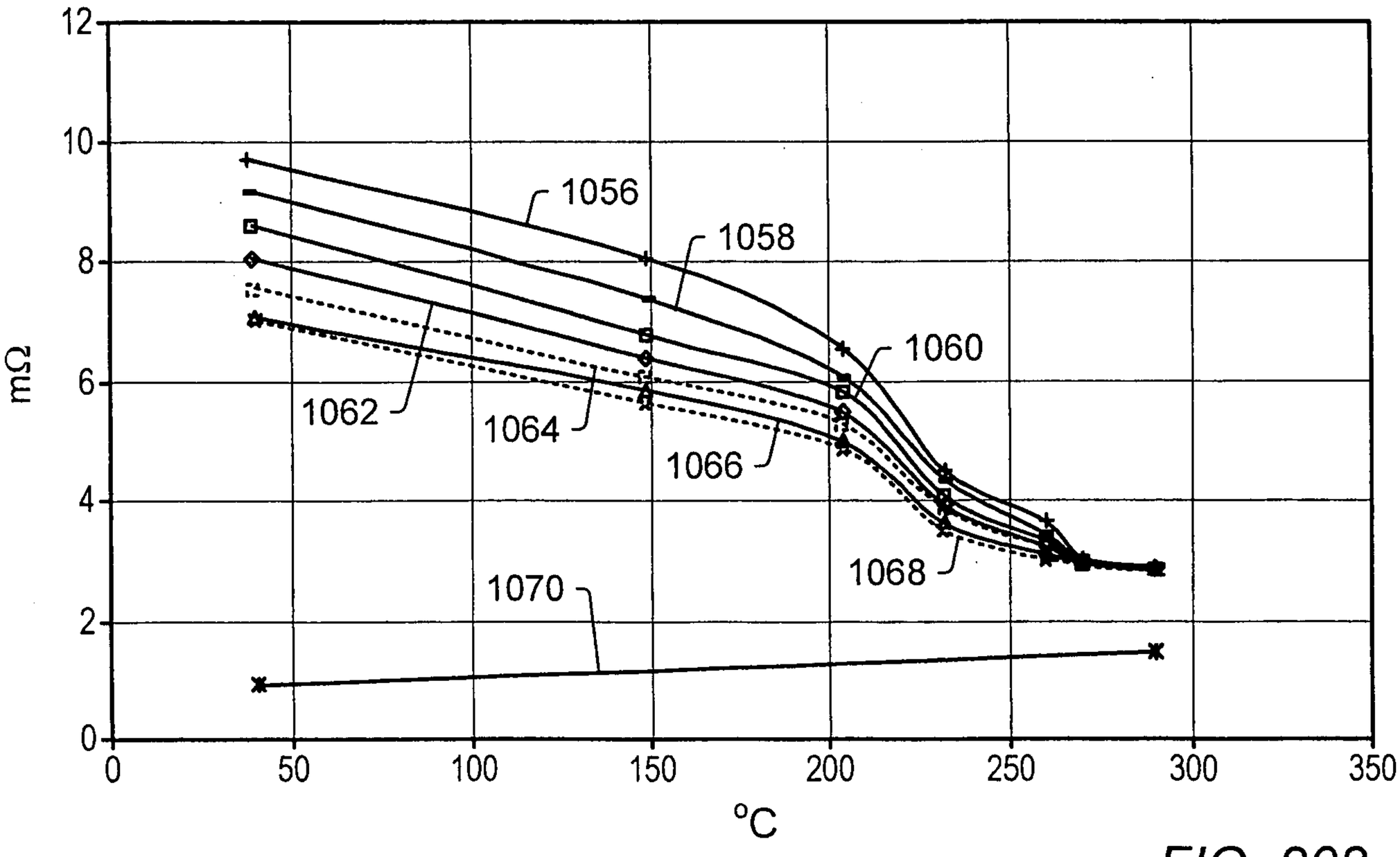


FIG. 208

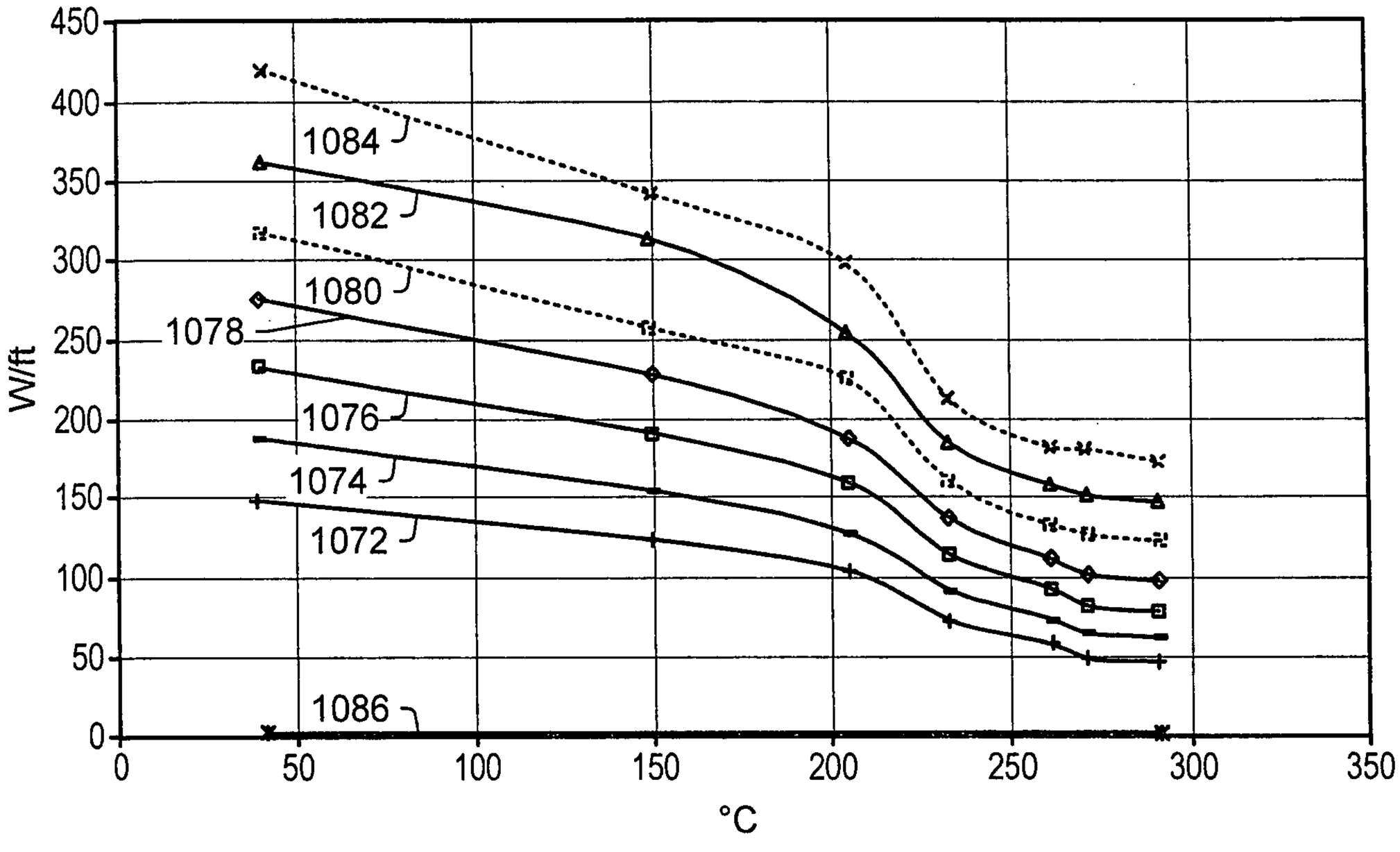


FIG. 209

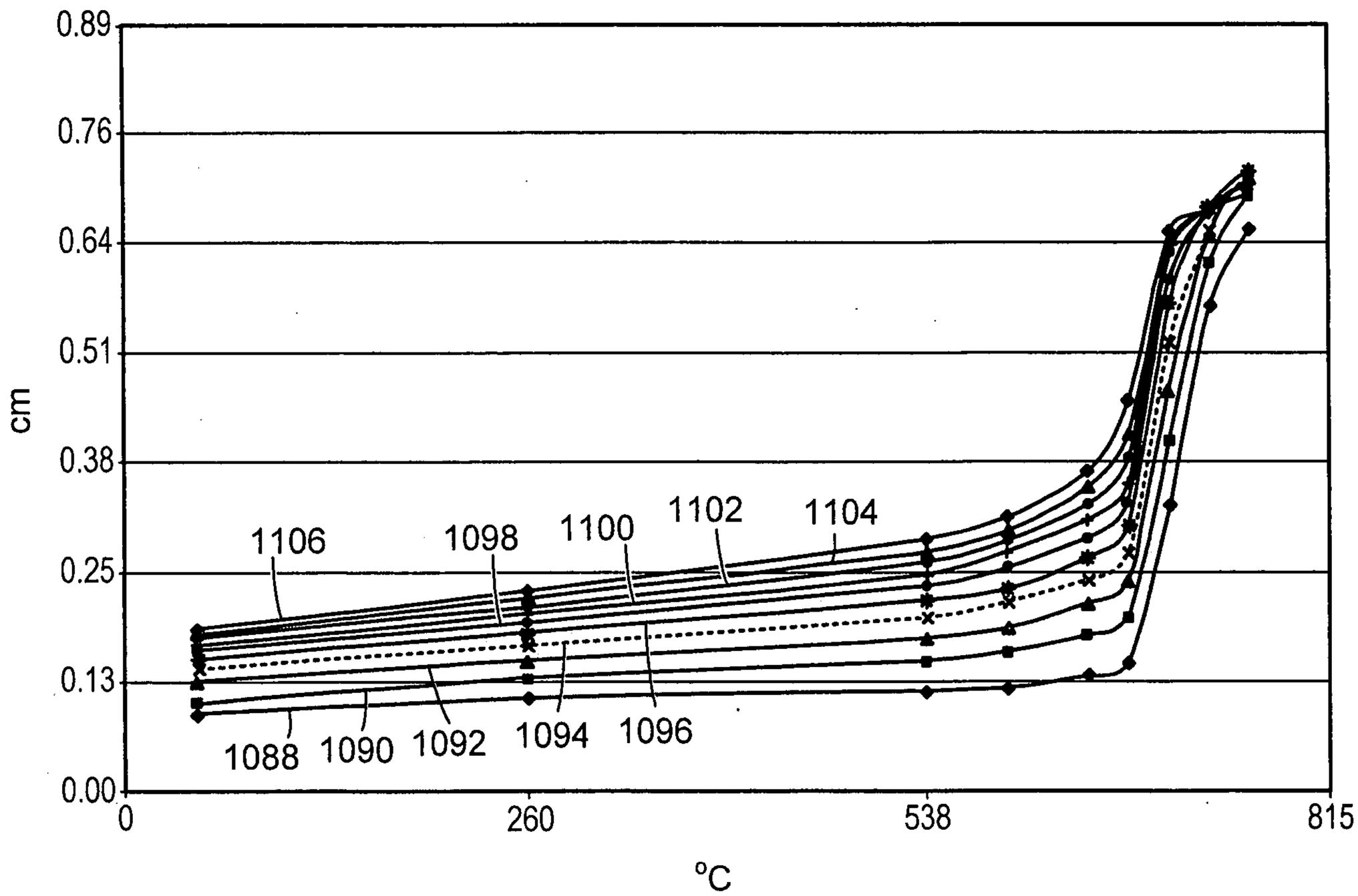


FIG. 210

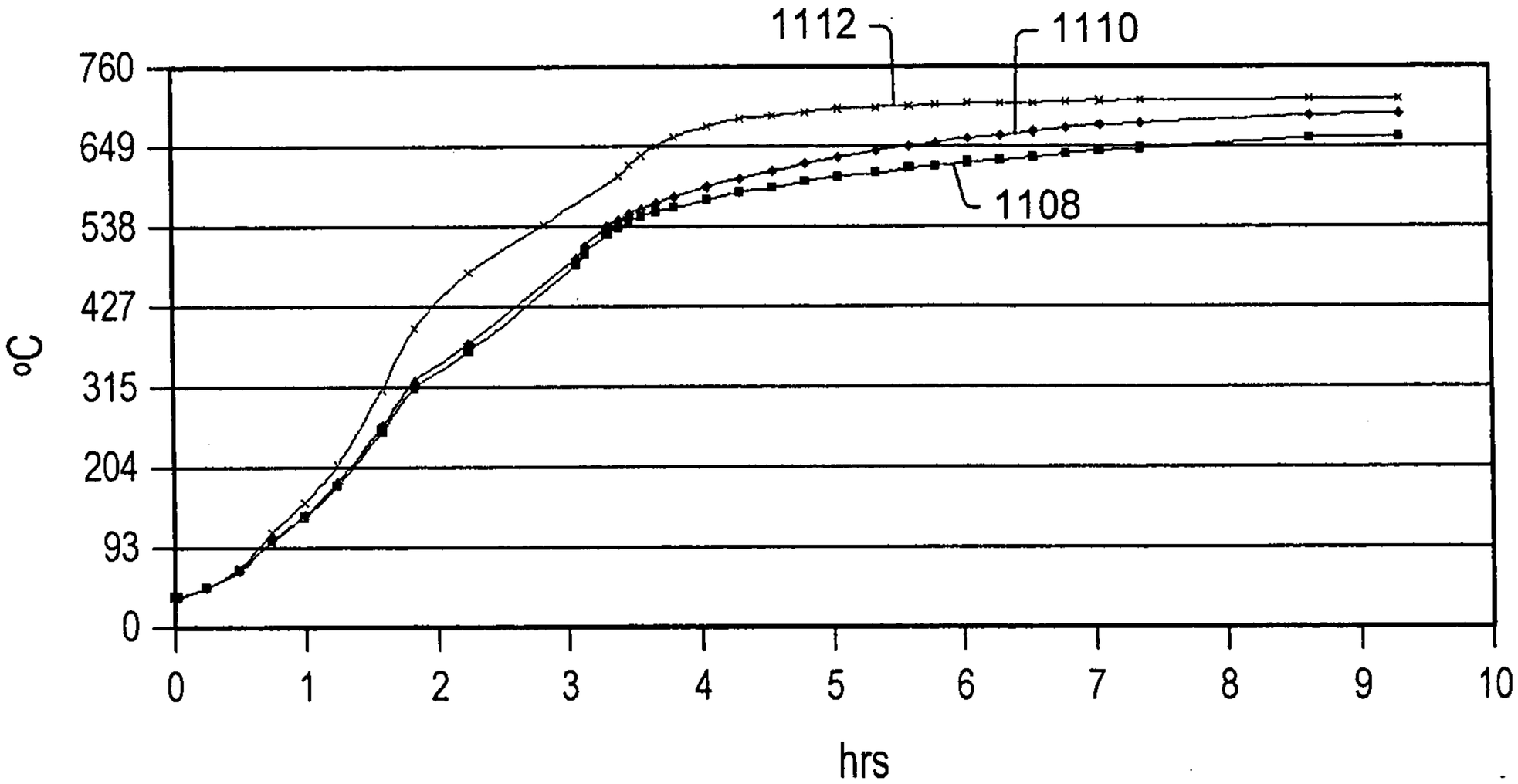


FIG. 211

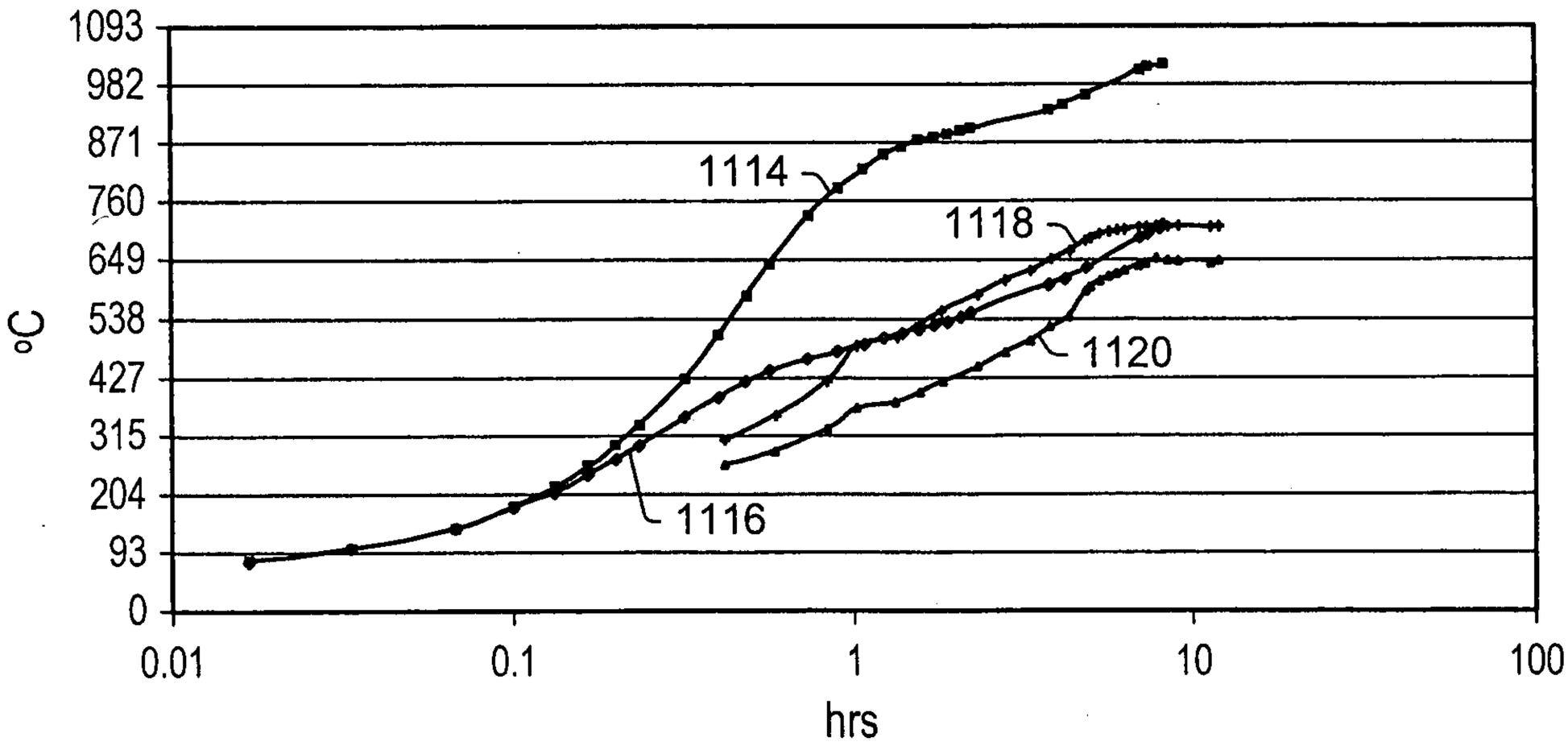


FIG. 212

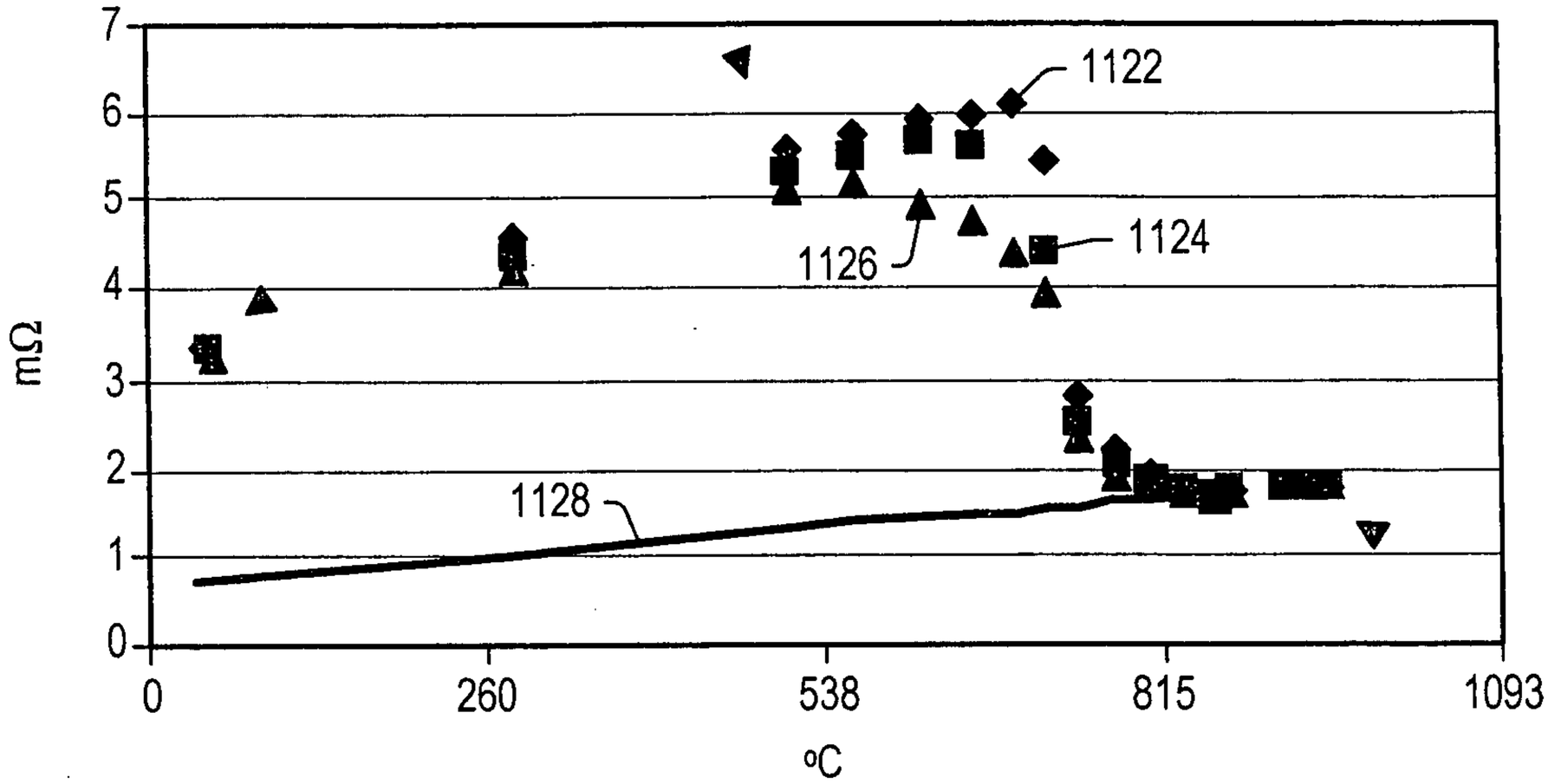


FIG. 213

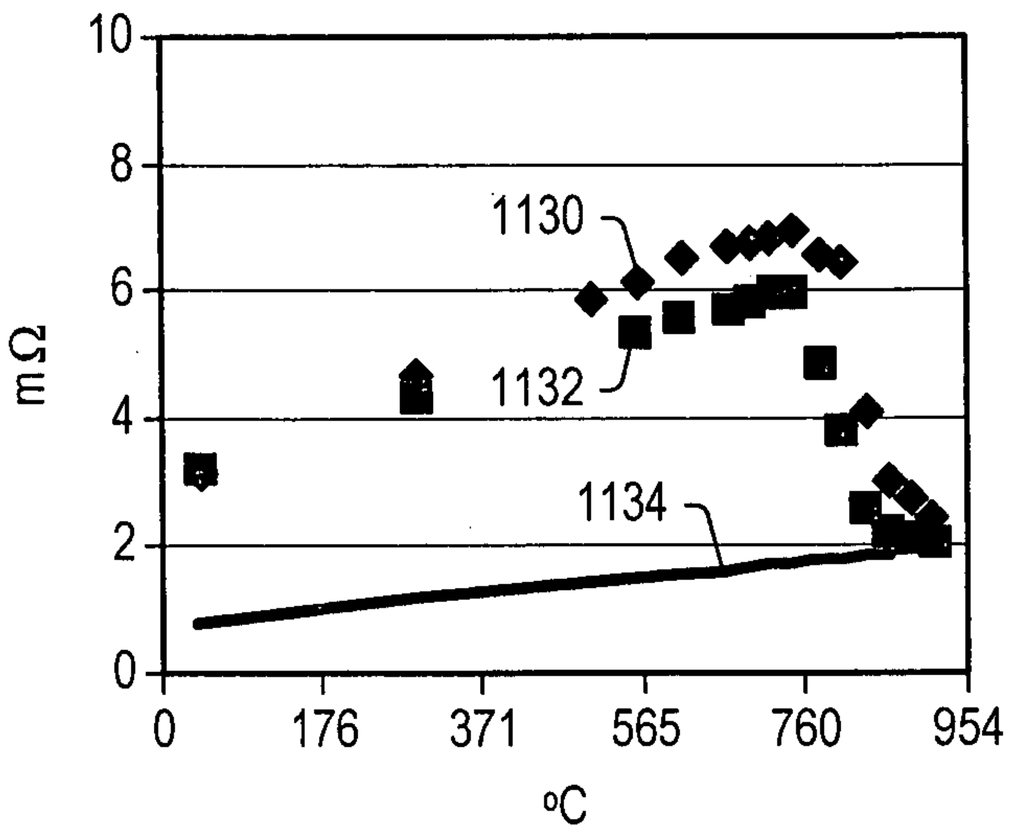


FIG. 214

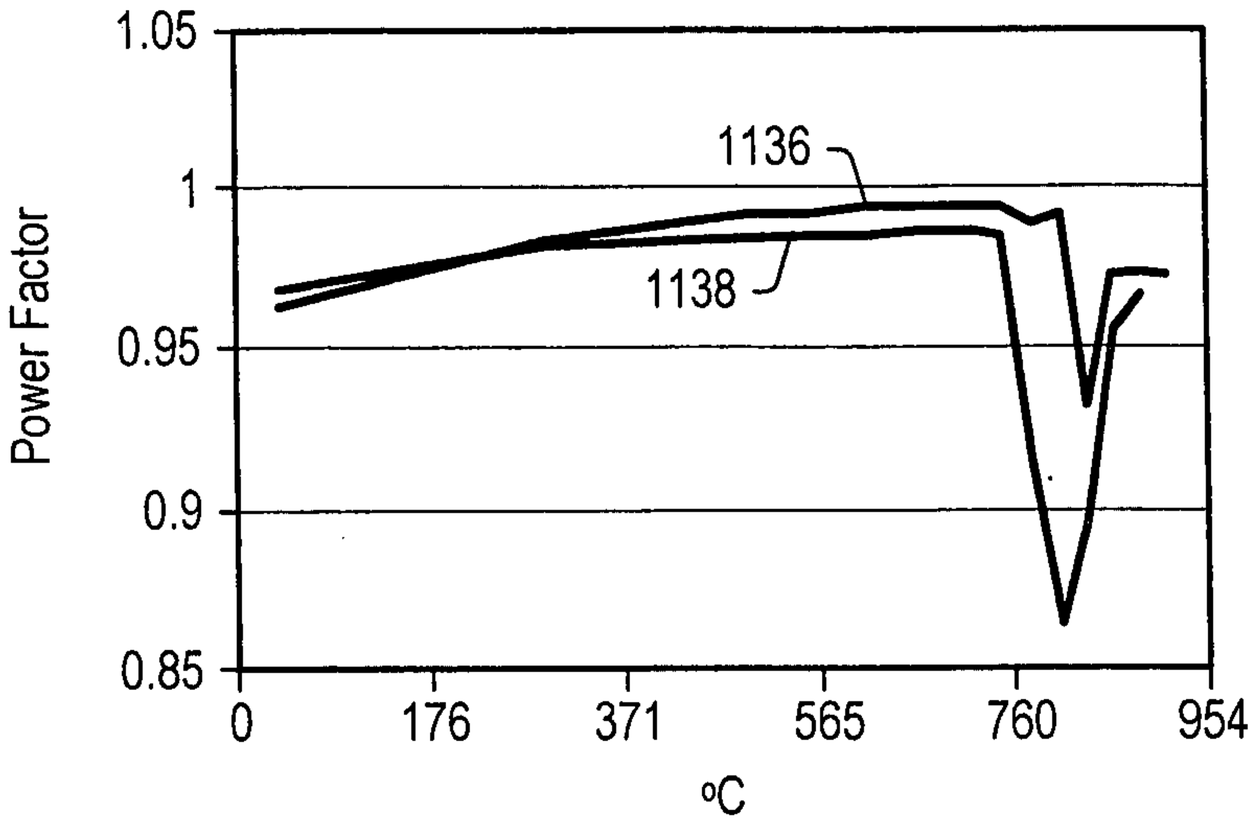


FIG. 215

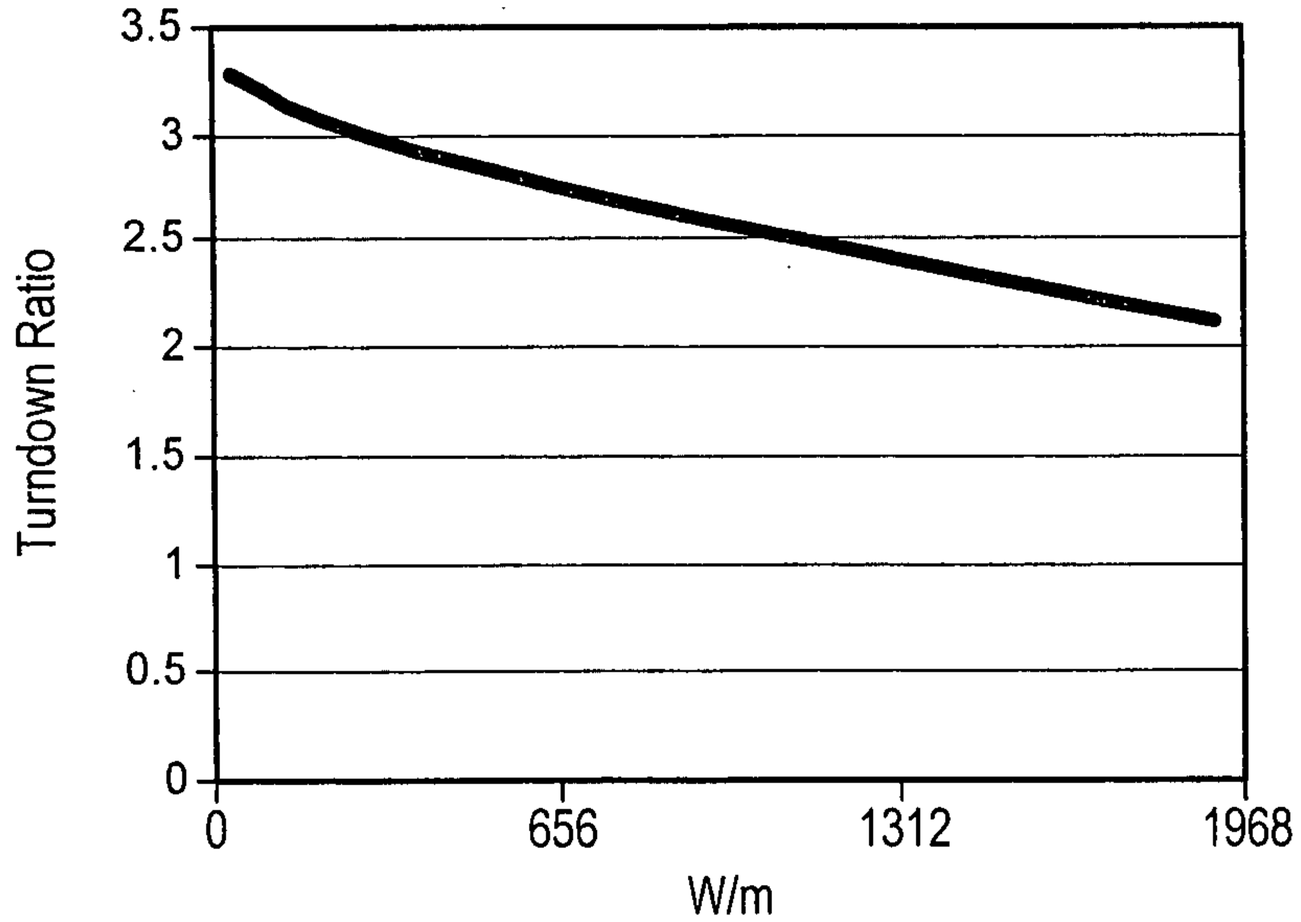


FIG. 216

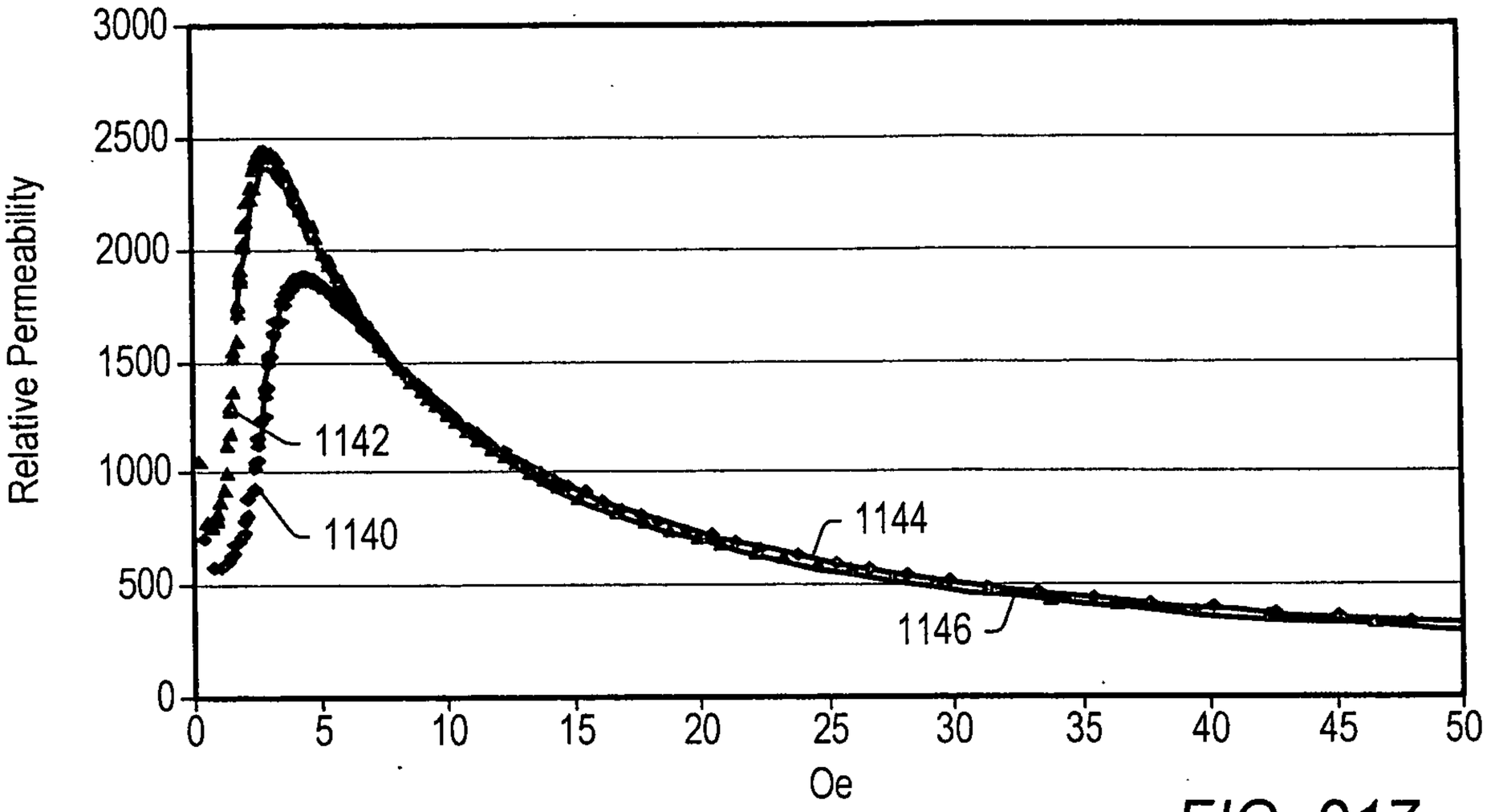


FIG. 217

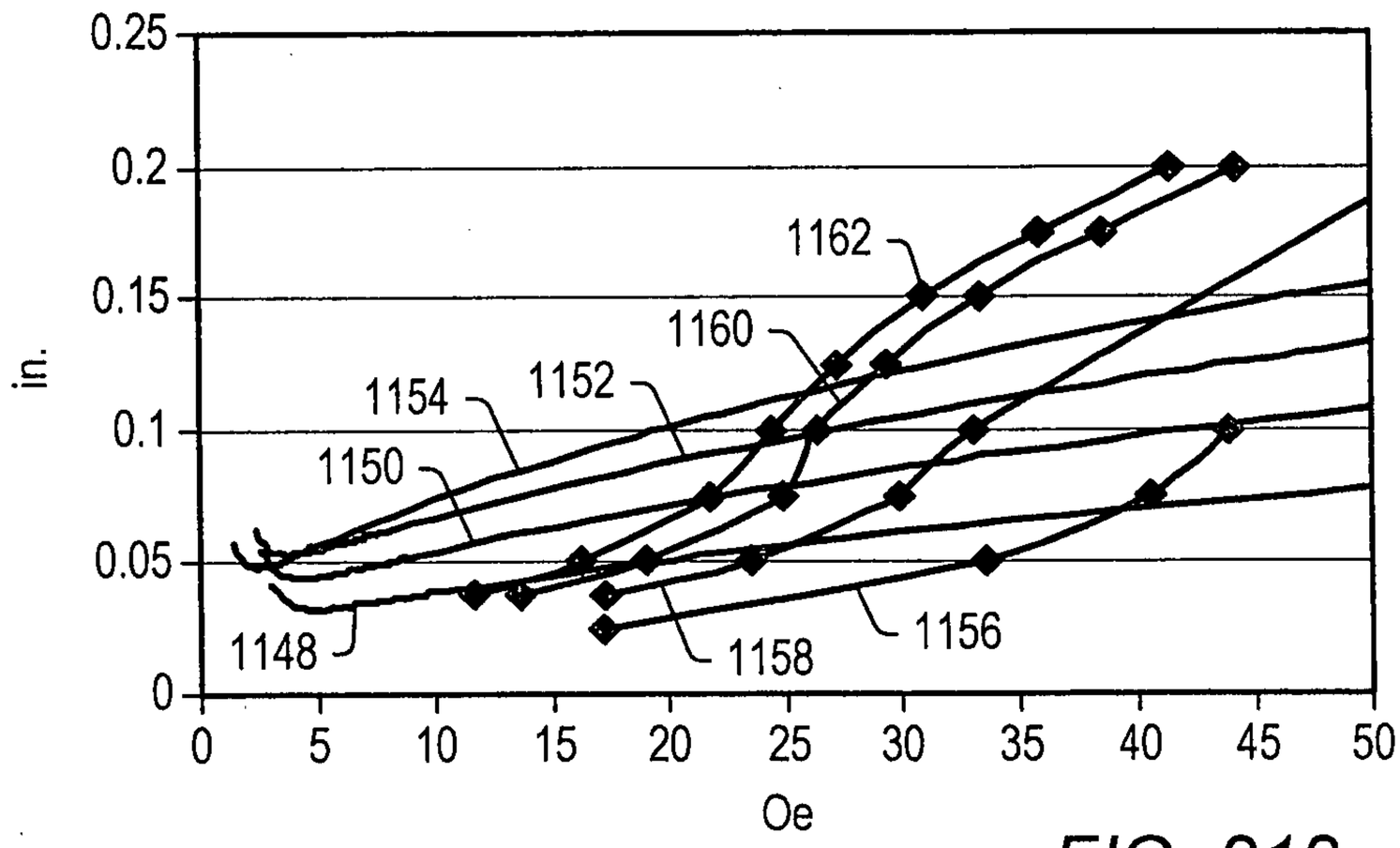


FIG. 218

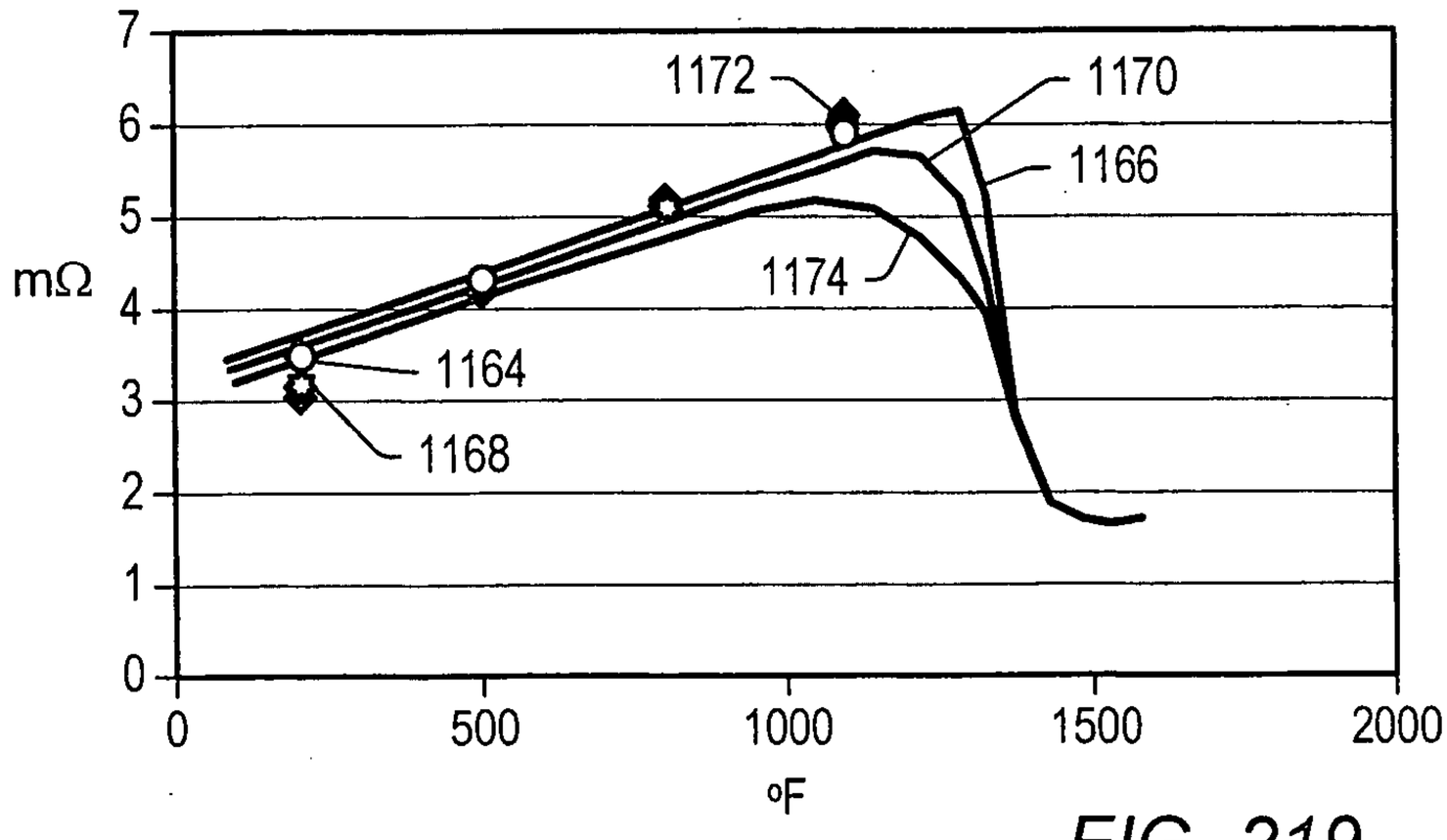


FIG. 219

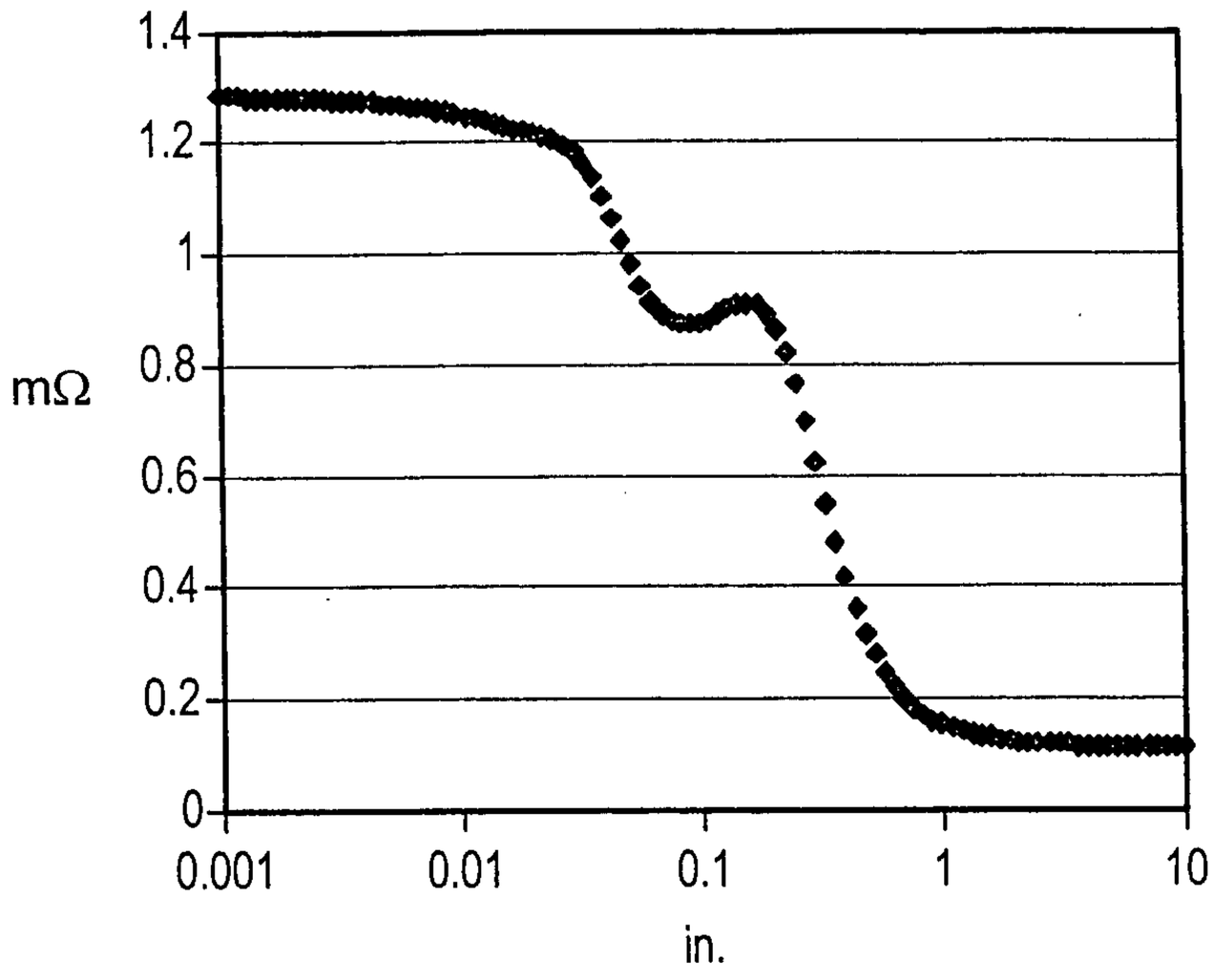


FIG. 220

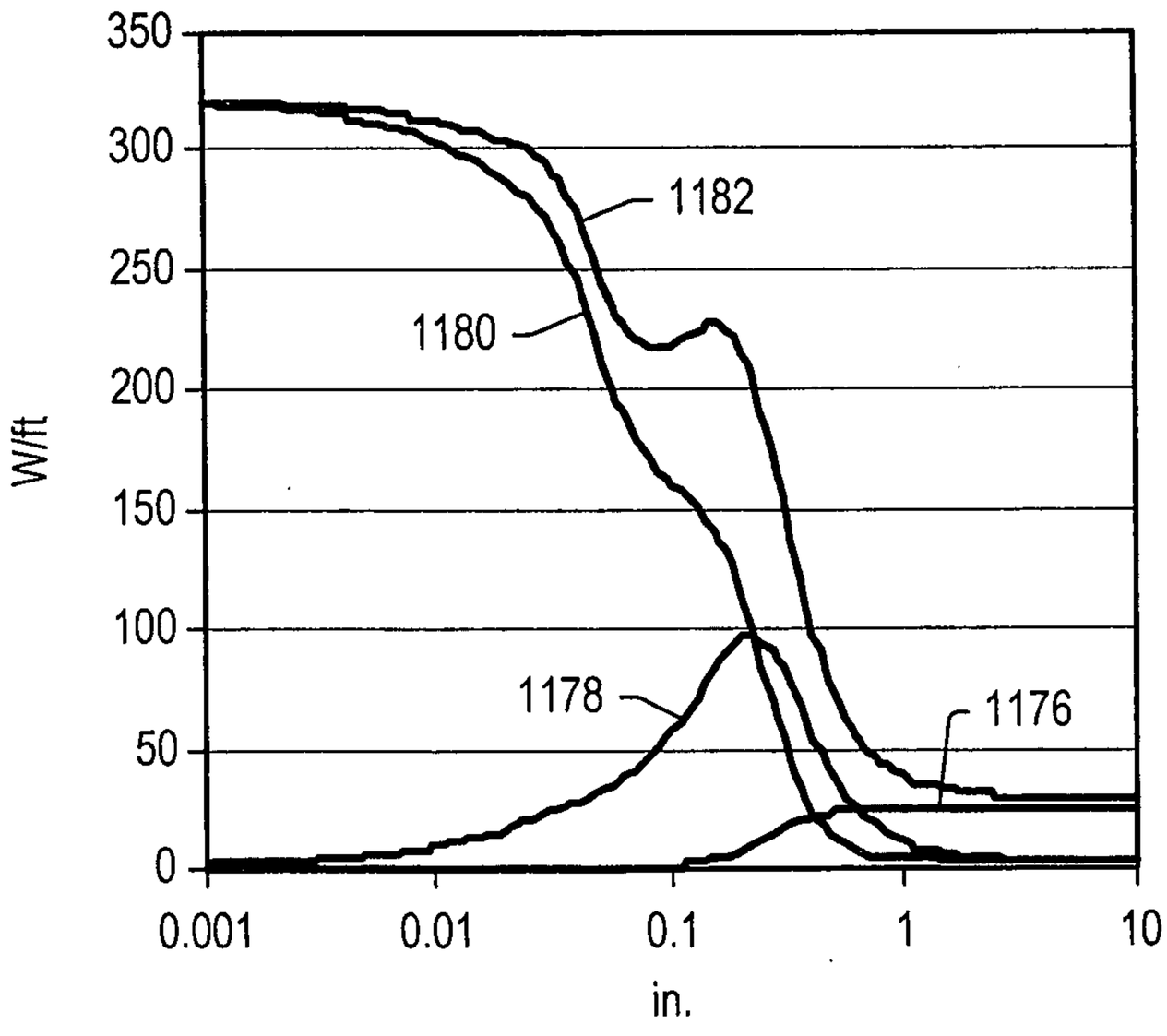


FIG. 221

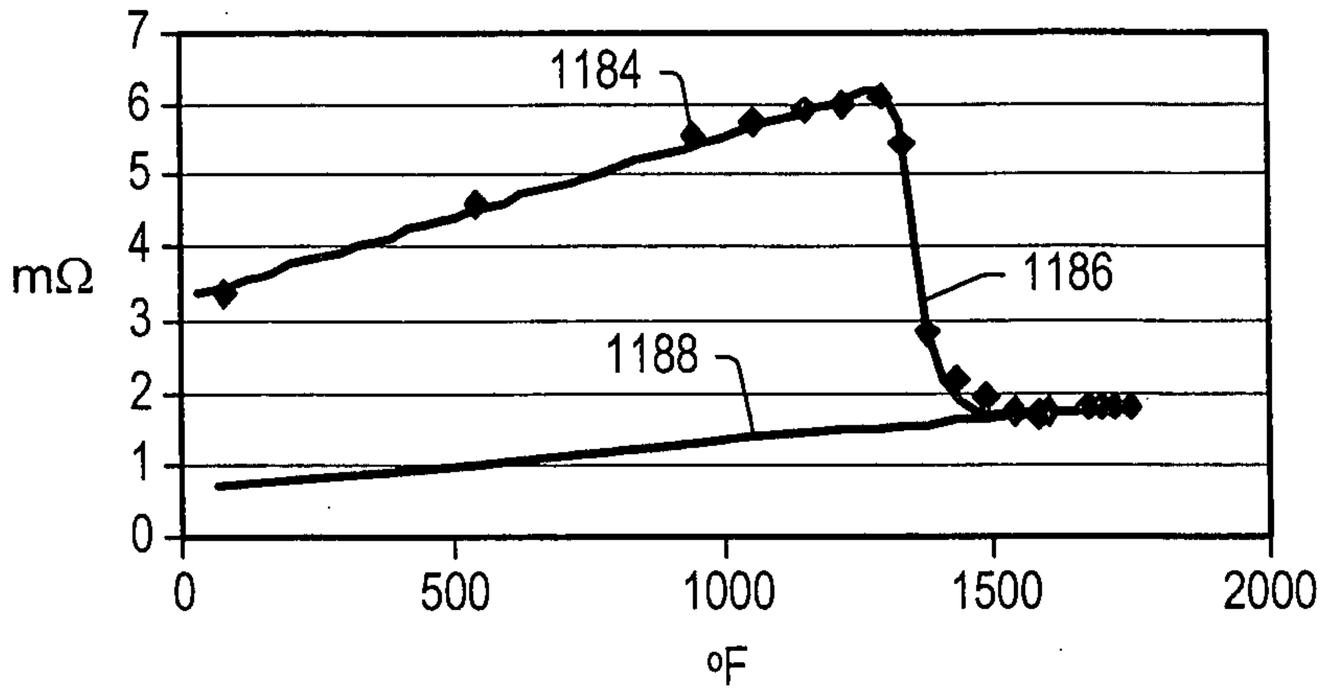


FIG. 222A

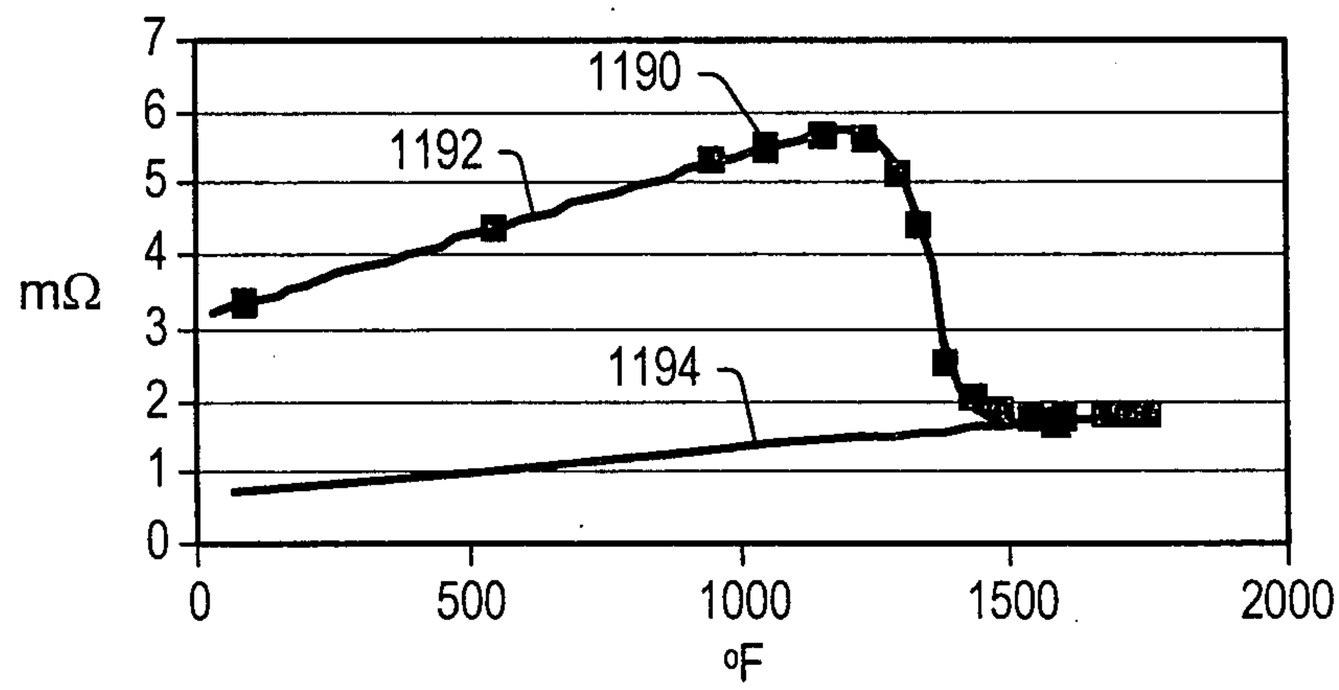


FIG. 222B

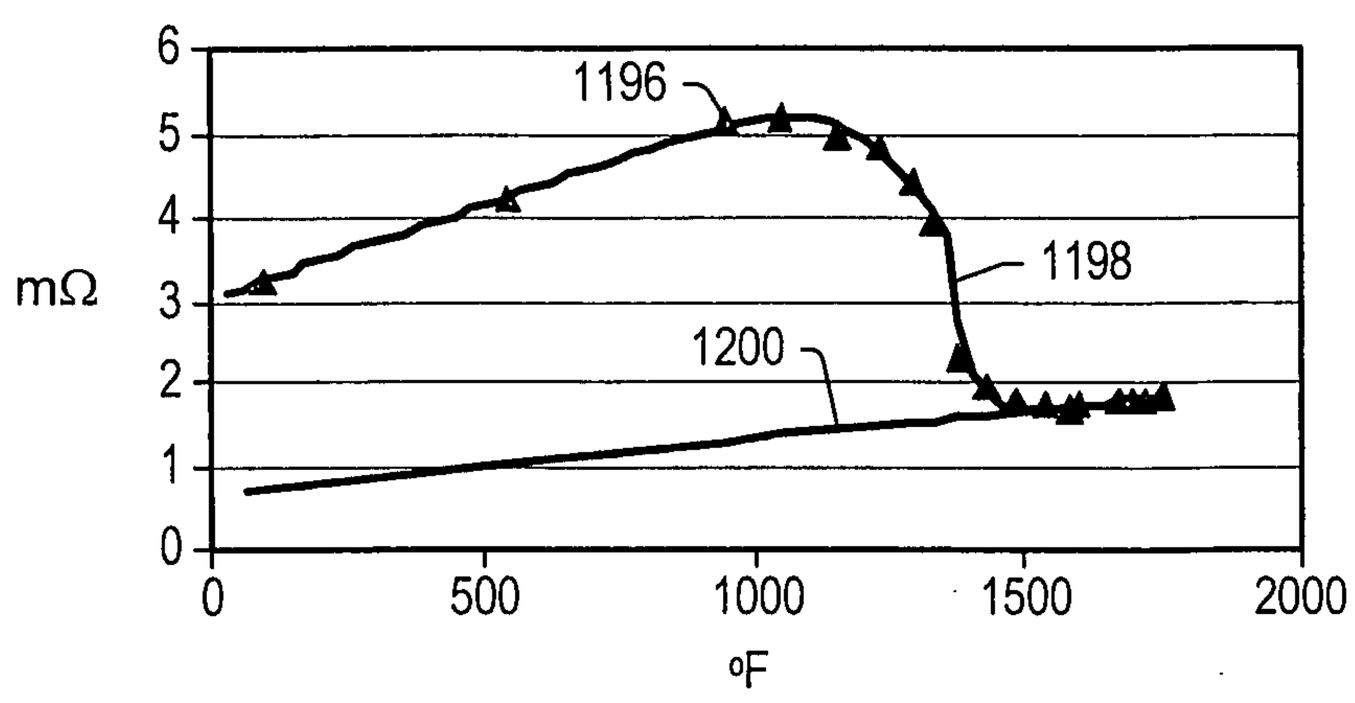


FIG. 222C

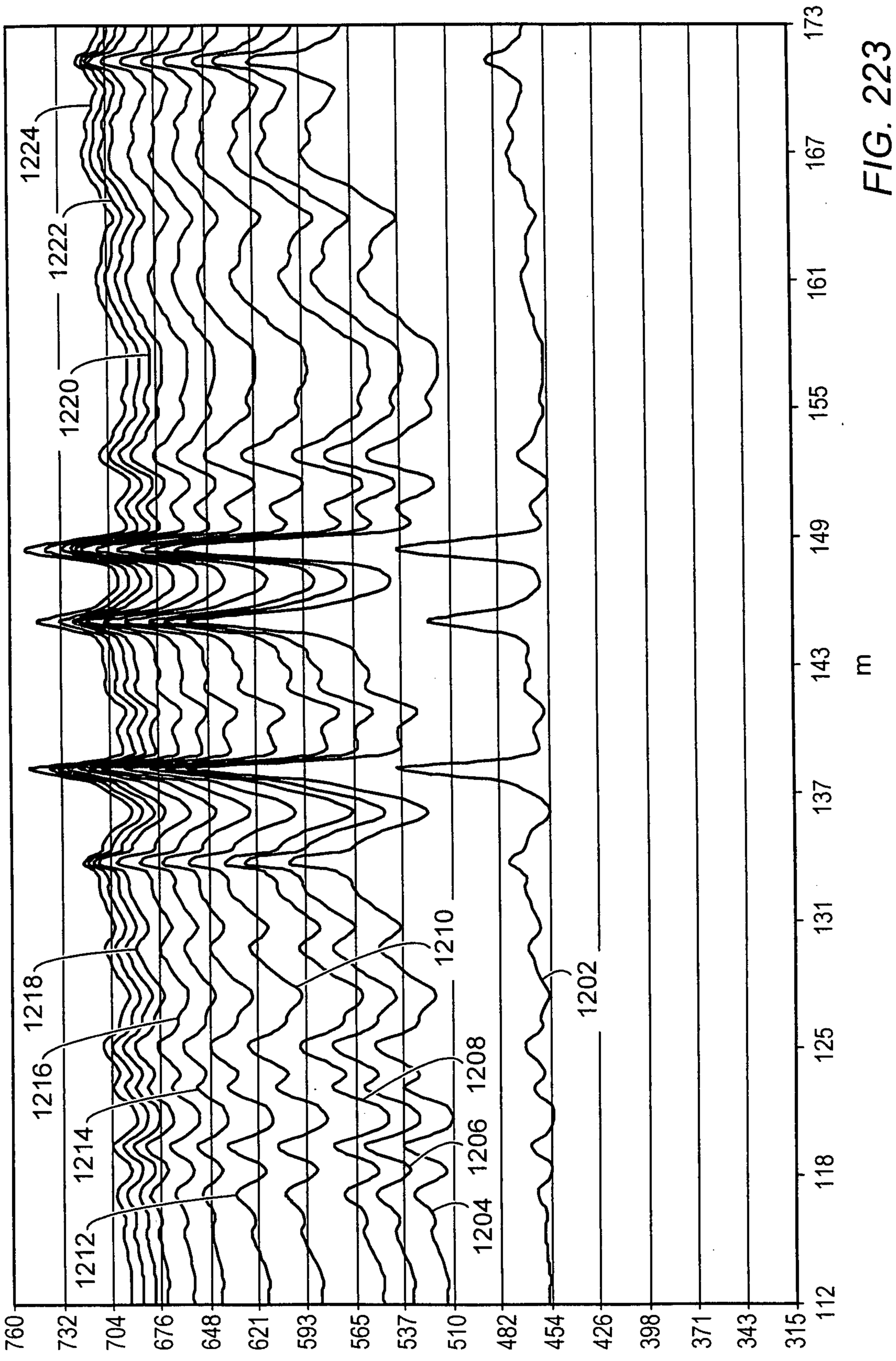

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FIG. 223

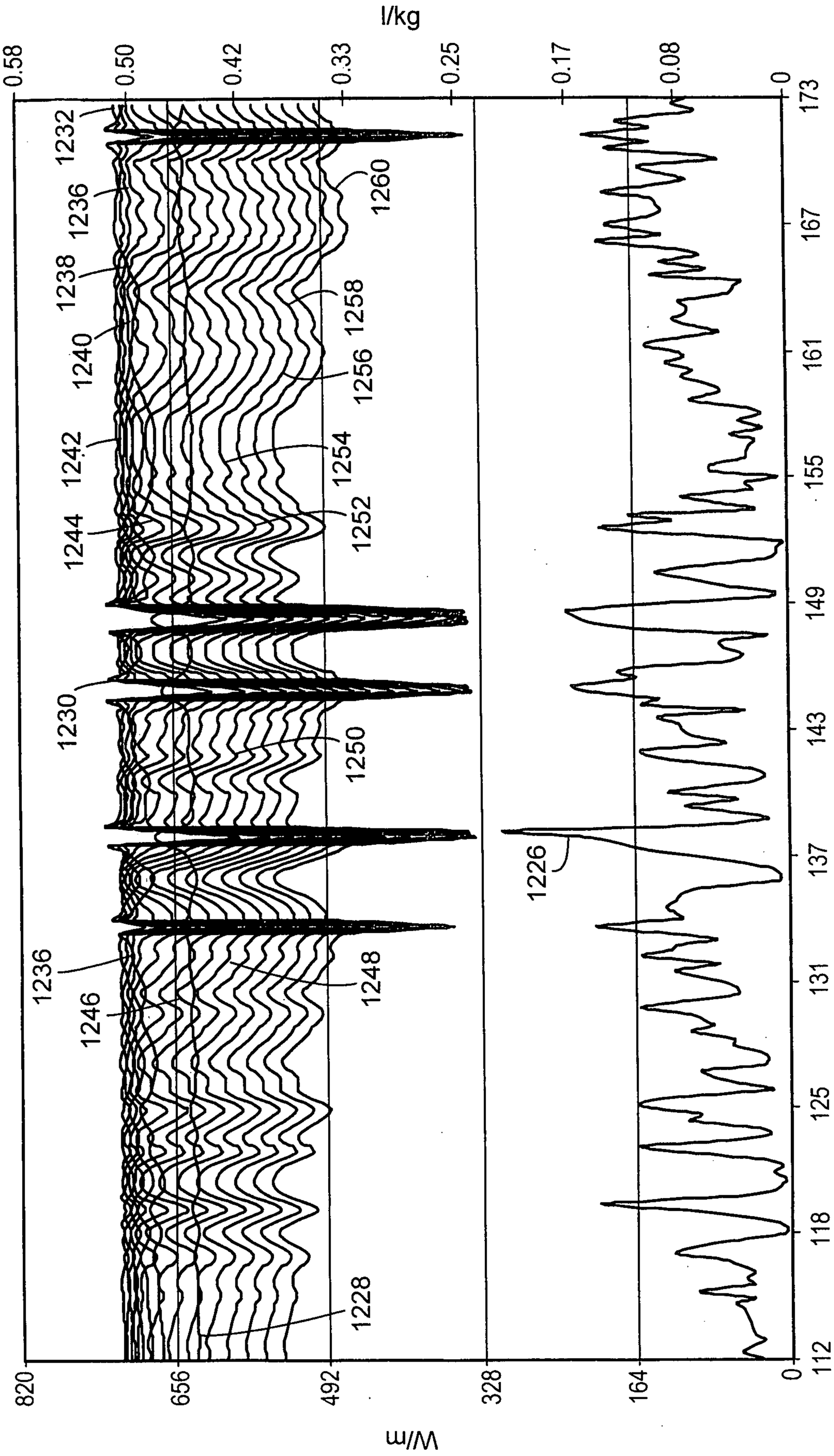

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FIG. 224

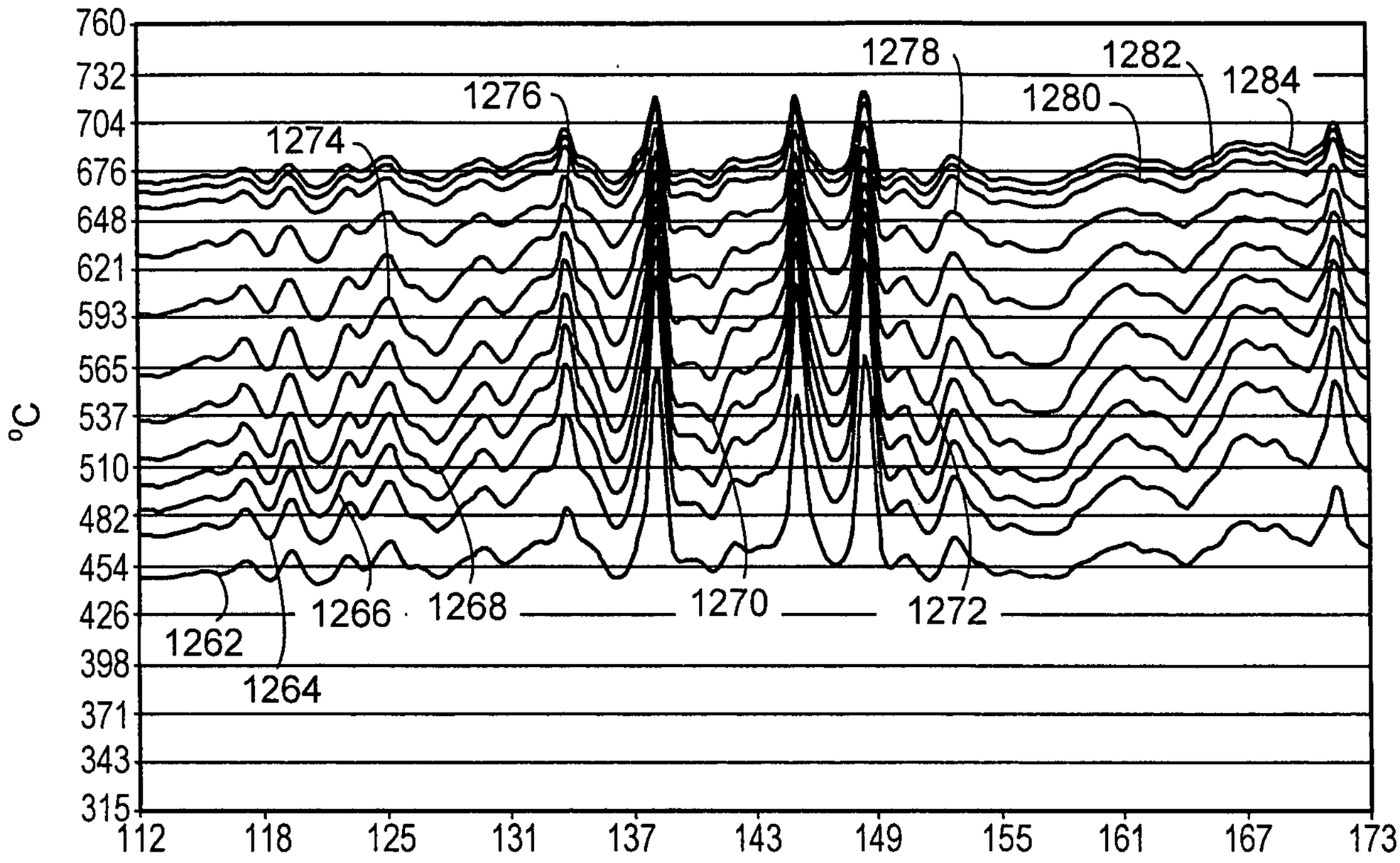


FIG. 225

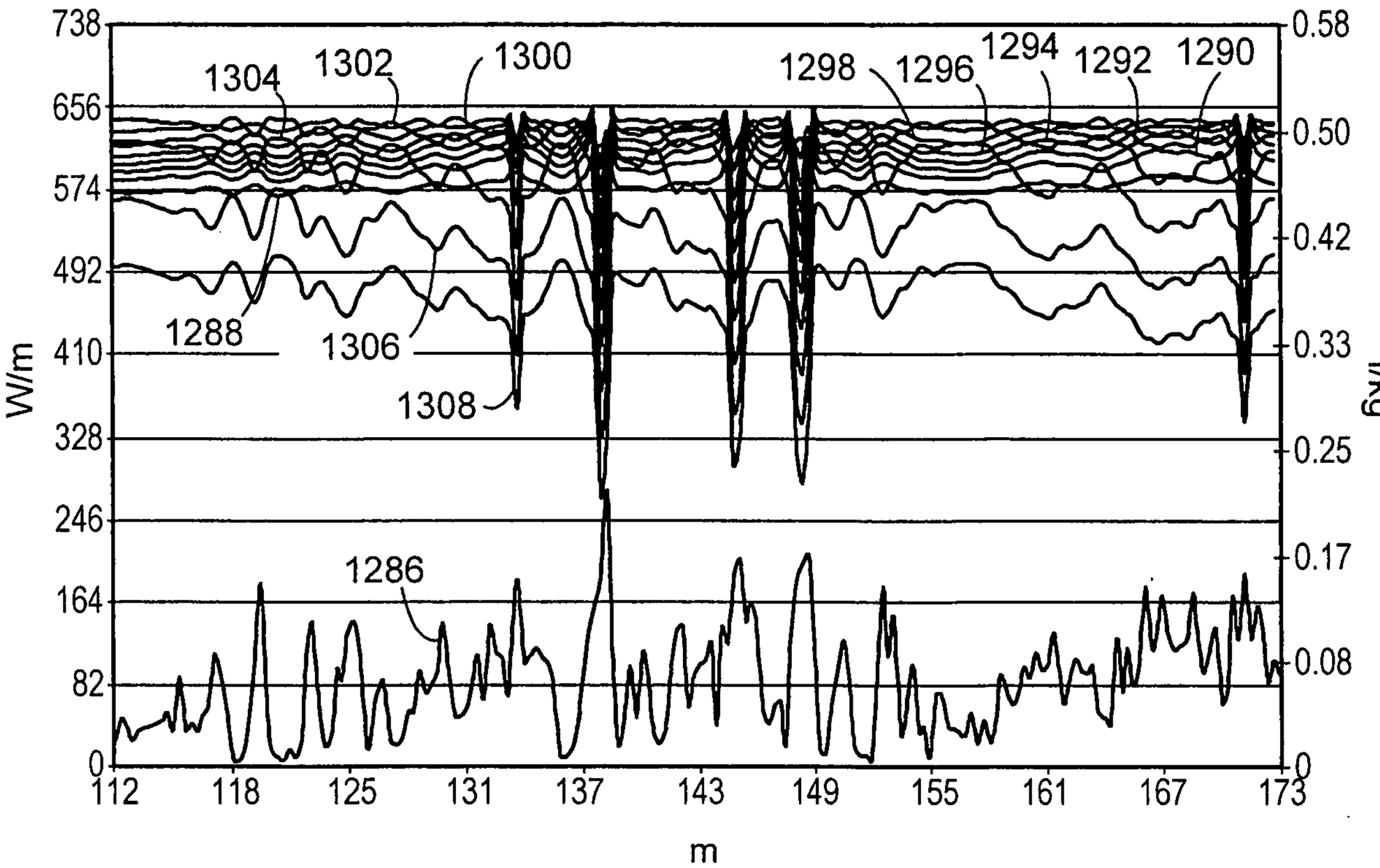


FIG. 226

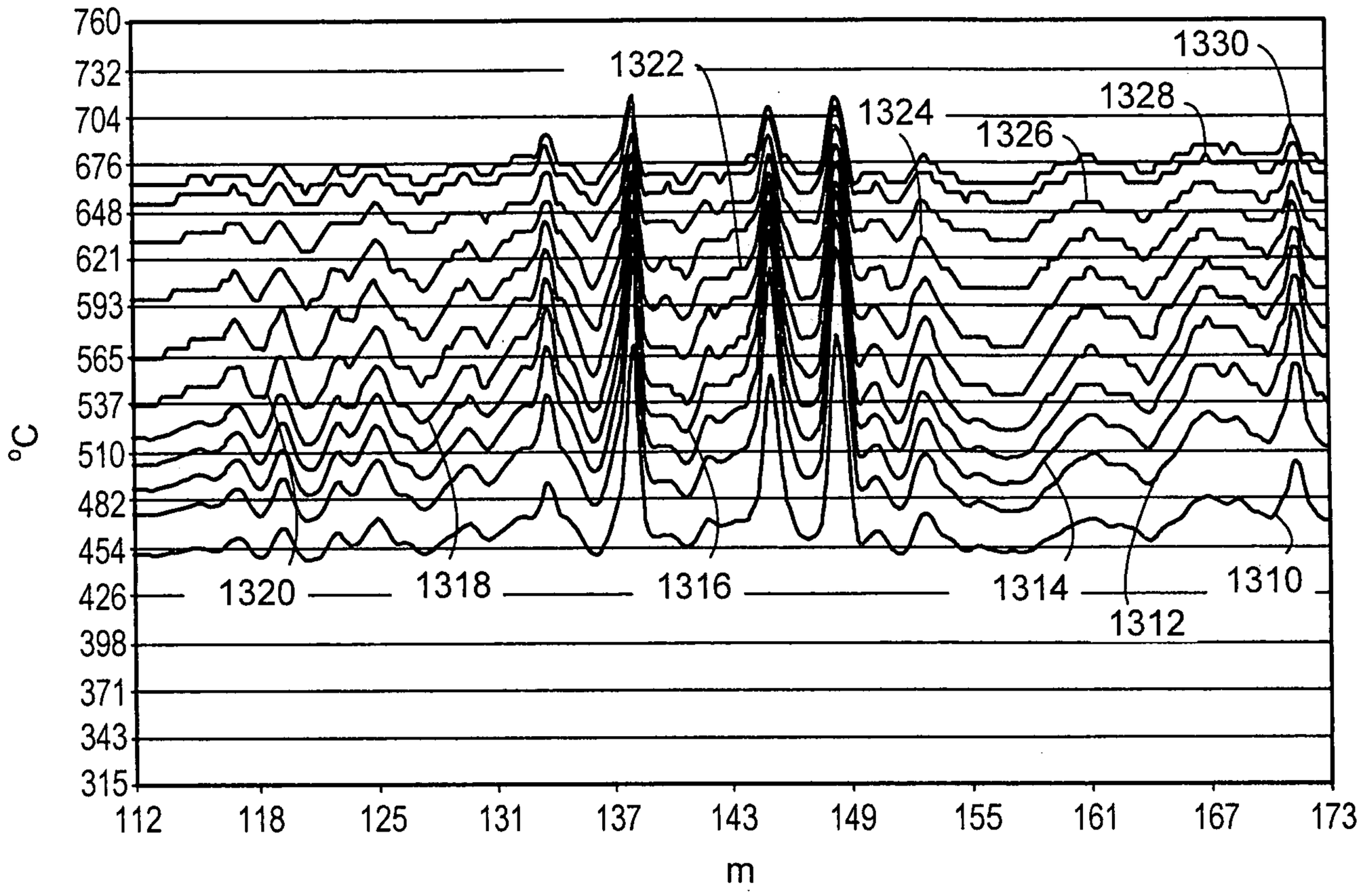


FIG. 227

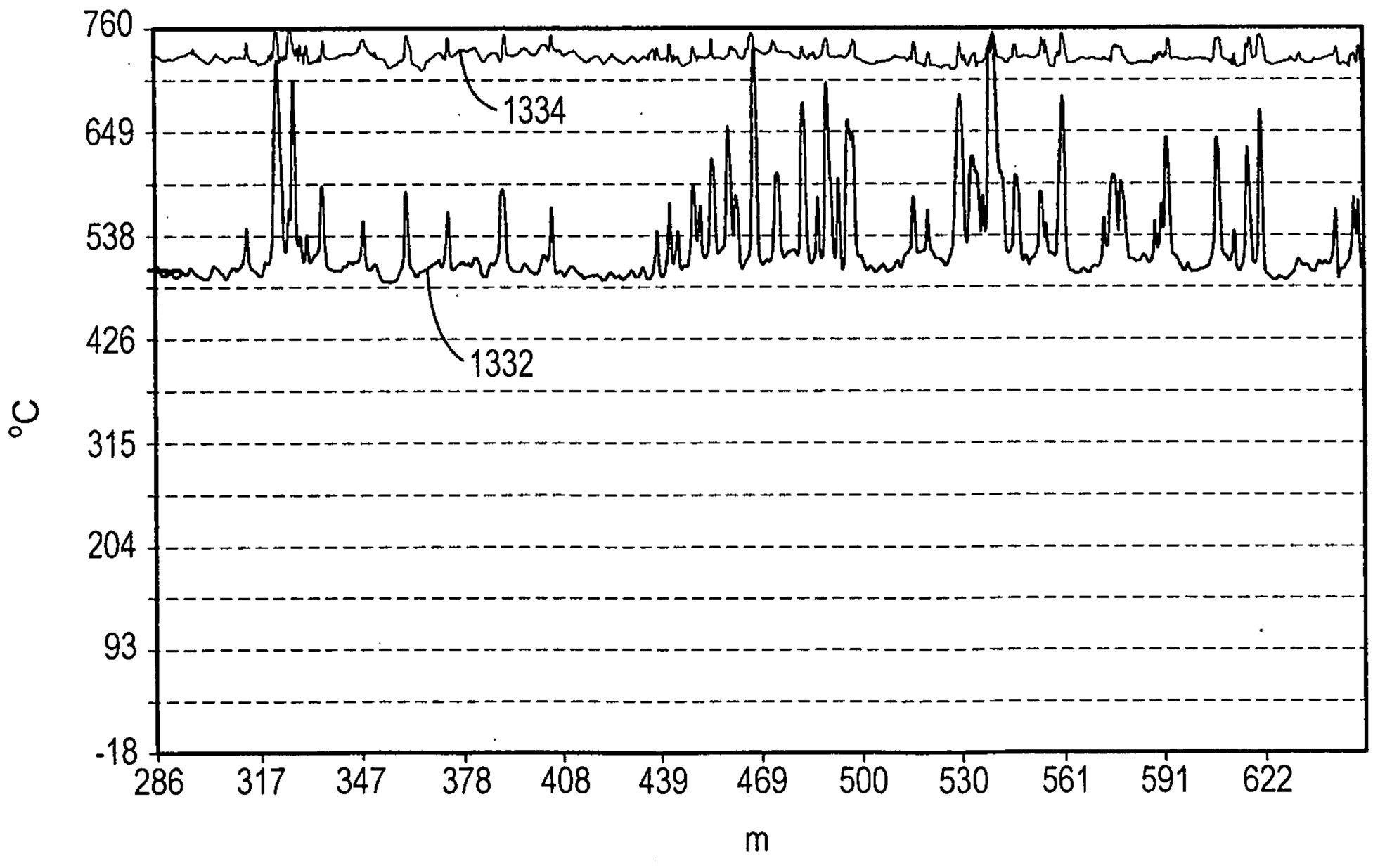


FIG. 228

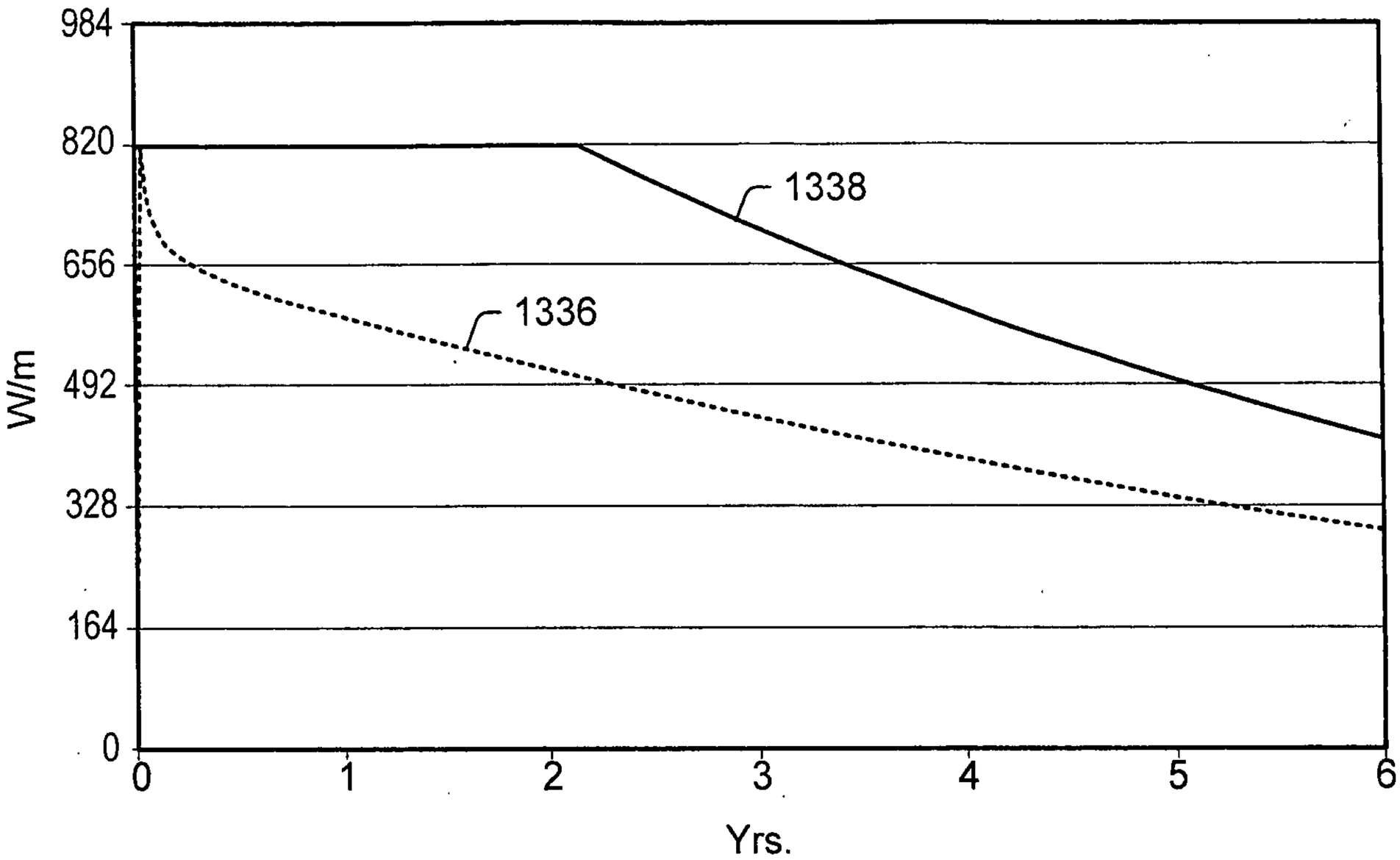


FIG. 229

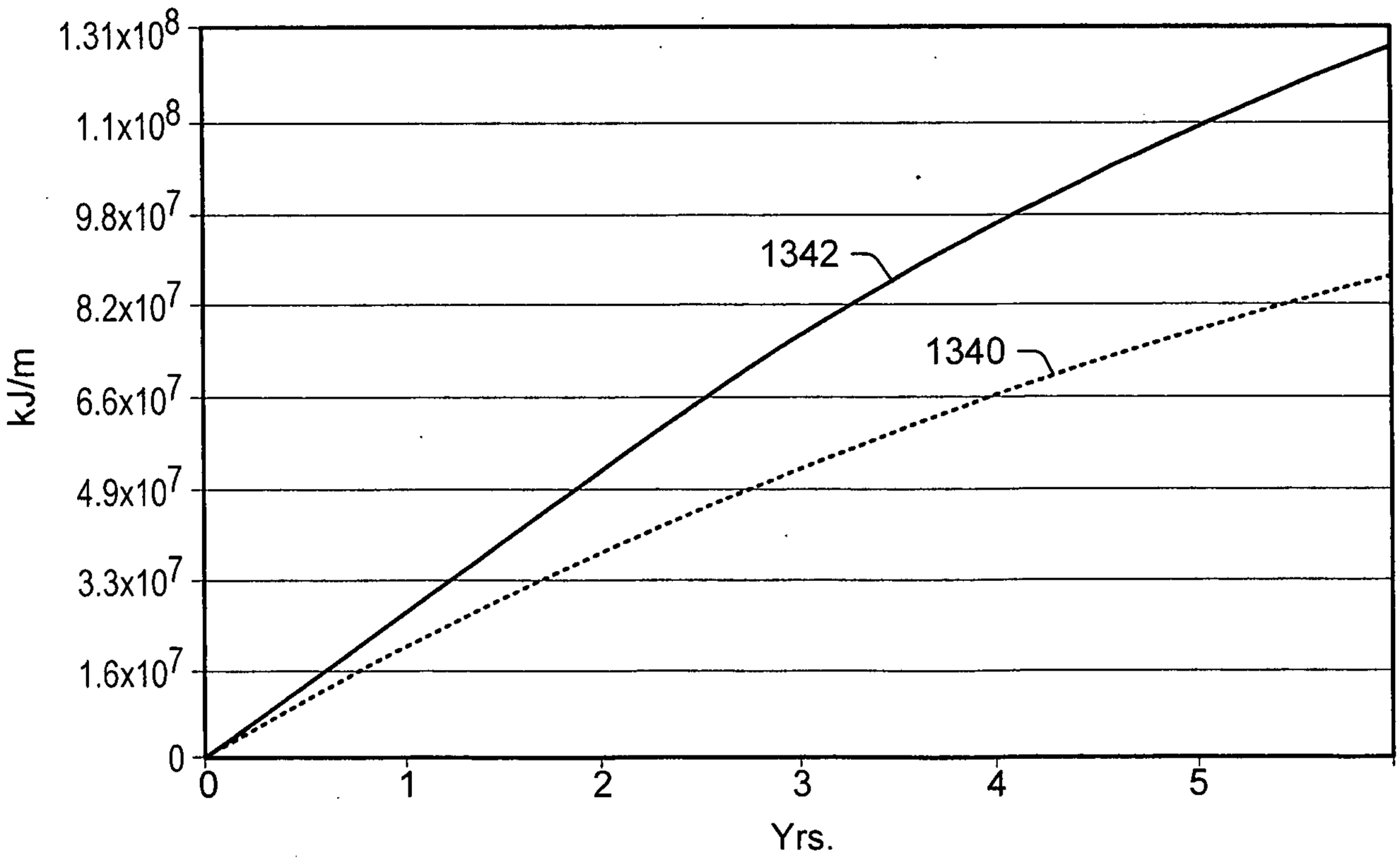


FIG. 230

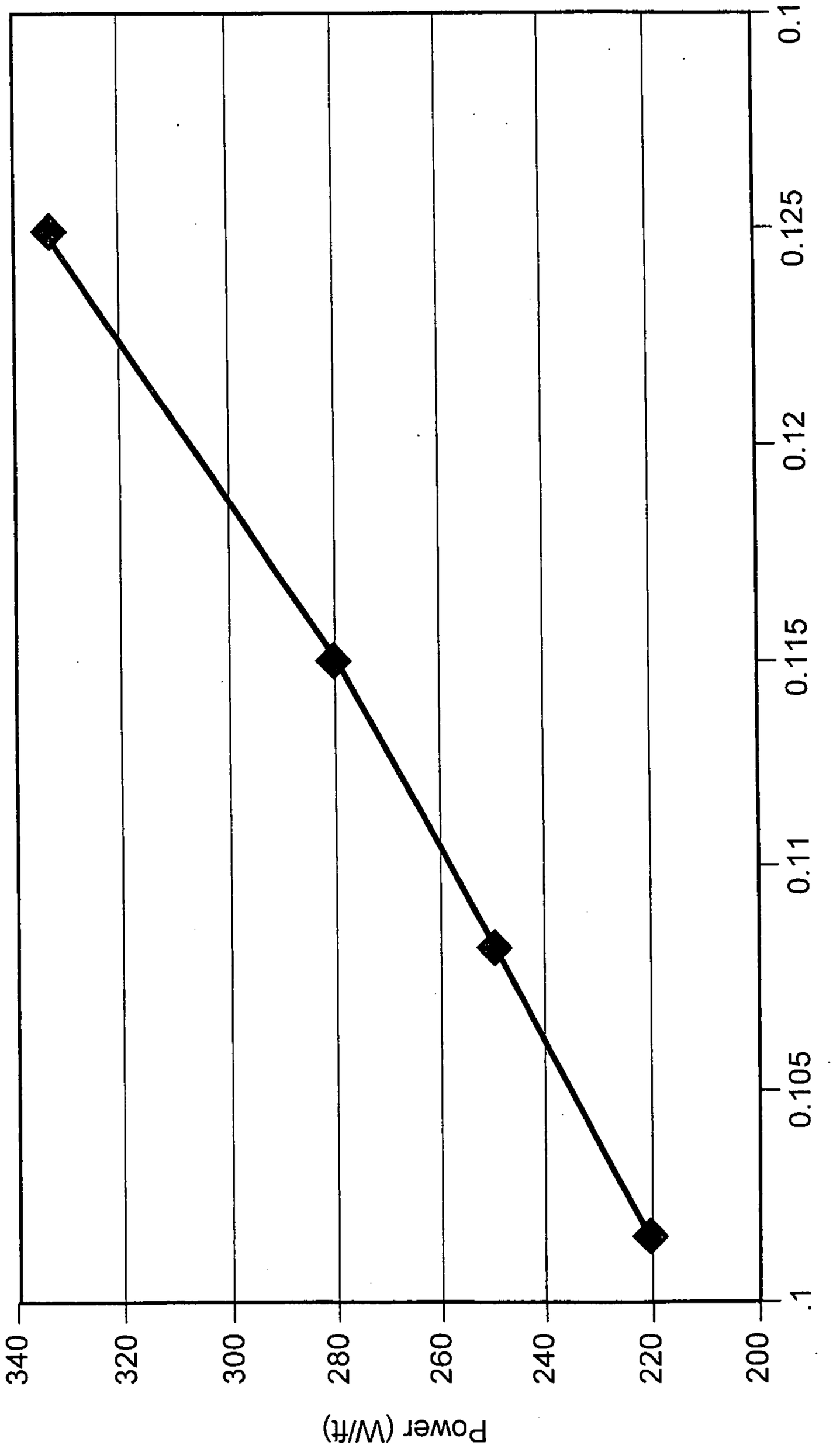

Thickness (in.)
0.1
0.105
0.11
0.115
0.12
0.125
Power (W/ft)
200
220
240
260
280
300
320
340

FIG. 231

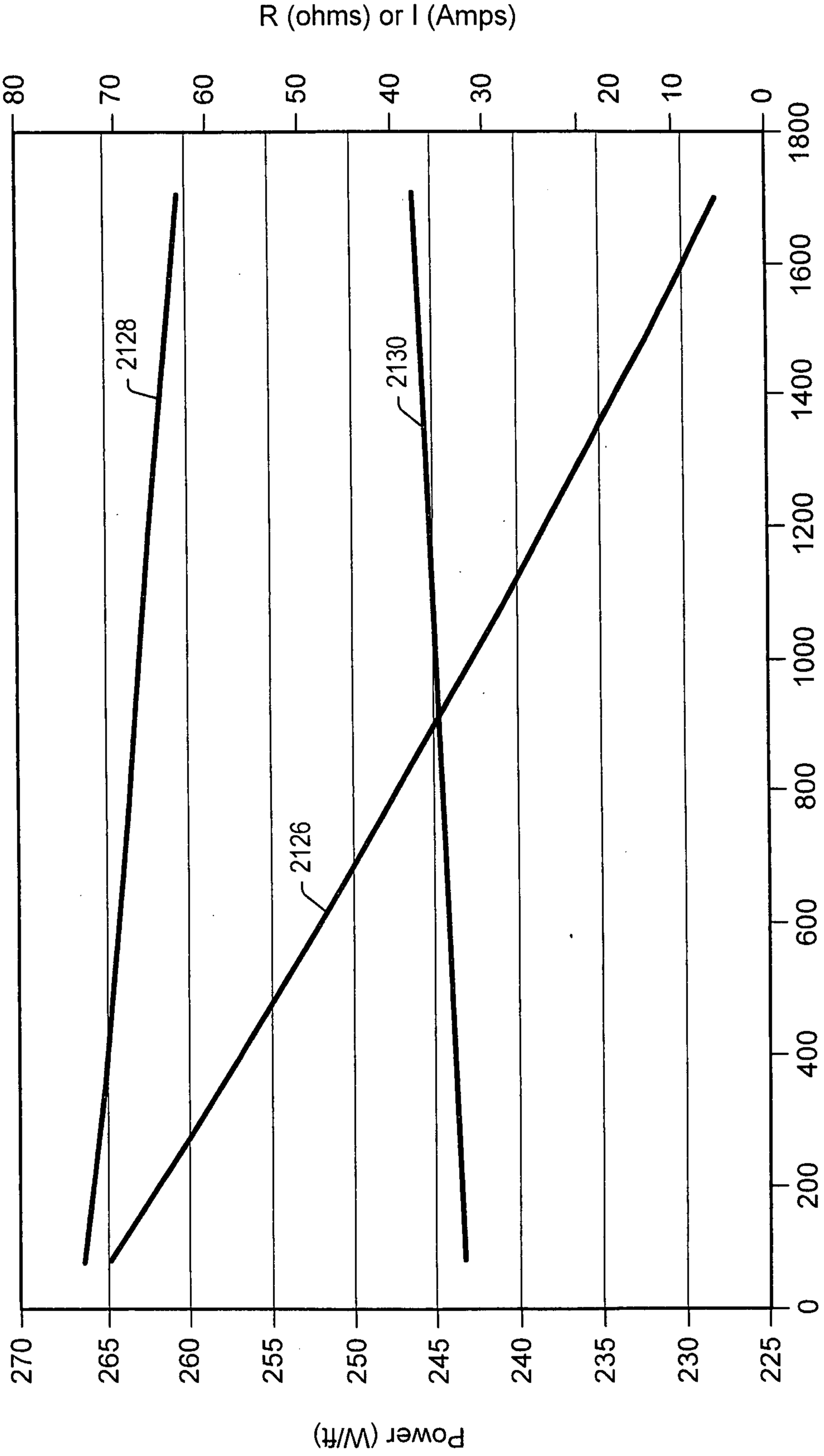

R (ohms) or I (Amps)
80
70
60
50
40
30
20
10
0
1800
1600
1400
1200
1000
800
600
400
200
0
T (°F)
2128
2130
2126
270
265
260
255
250
245
240
235
230
225
Power (W/ft)

FIG. 232

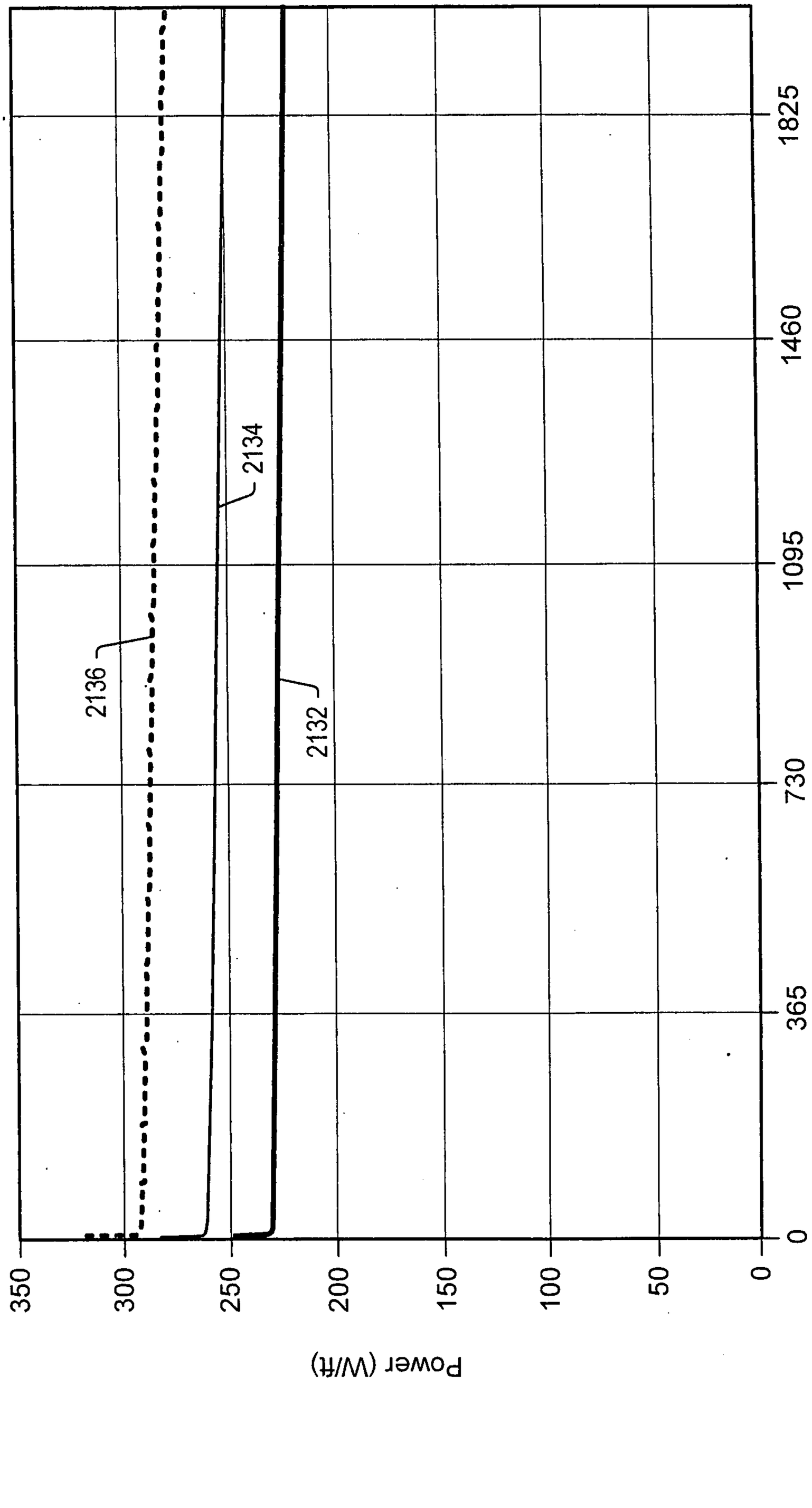

2134
2136
2132
Power (W/ft)
350
300
250
200
150
100
50
0
0
365
730
1095
1460
1825
Time (days)

FIG. 233

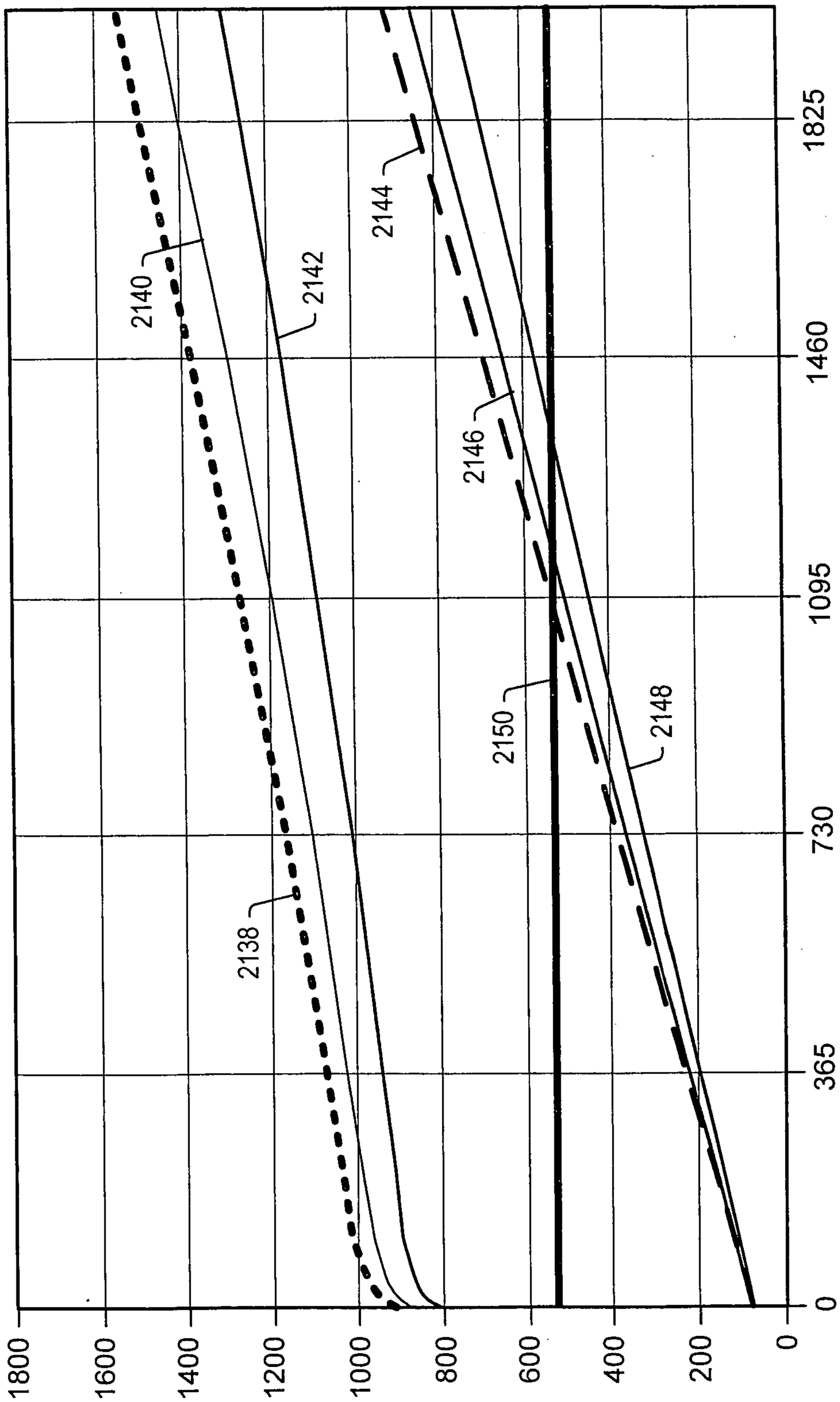

2140
2142
2144
2146
2148
2150
2138
1825
1460
1095
730
365
0
Time (days)
1800
1600
1400
1200
1000
800
600
400
200
0
T (°F)

FIG. 234

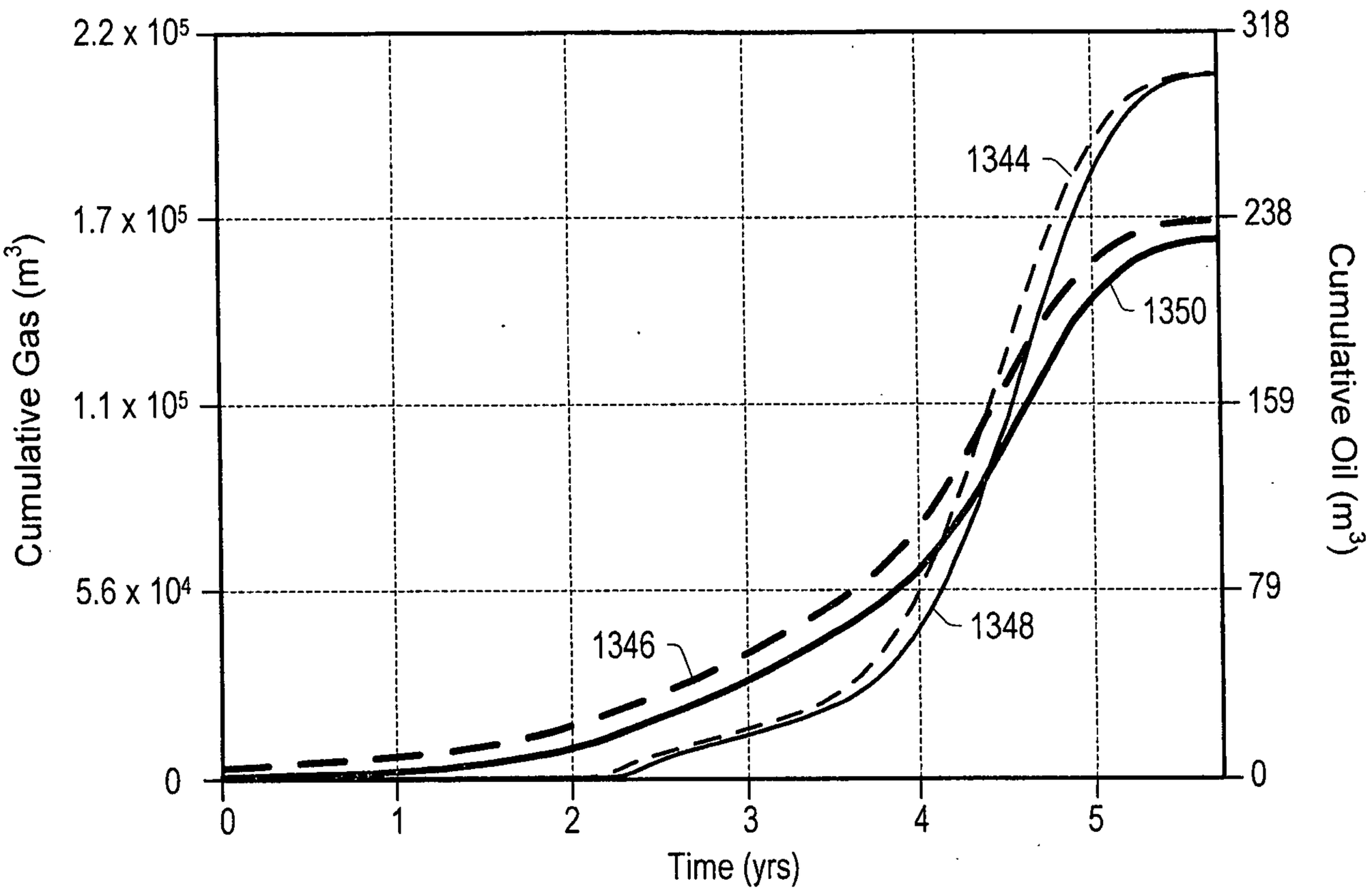

2.2 x 10^5
1.7 x 10^5
1.1 x 10^5
5.6 x 10^4
0
Cumulative Gas (m^3)
318
238
159
79
0
Cumulative Oil (m^3)
1344
1350
1346
1348
0
1
2
3
4
5
Time (yrs)

FIG. 235

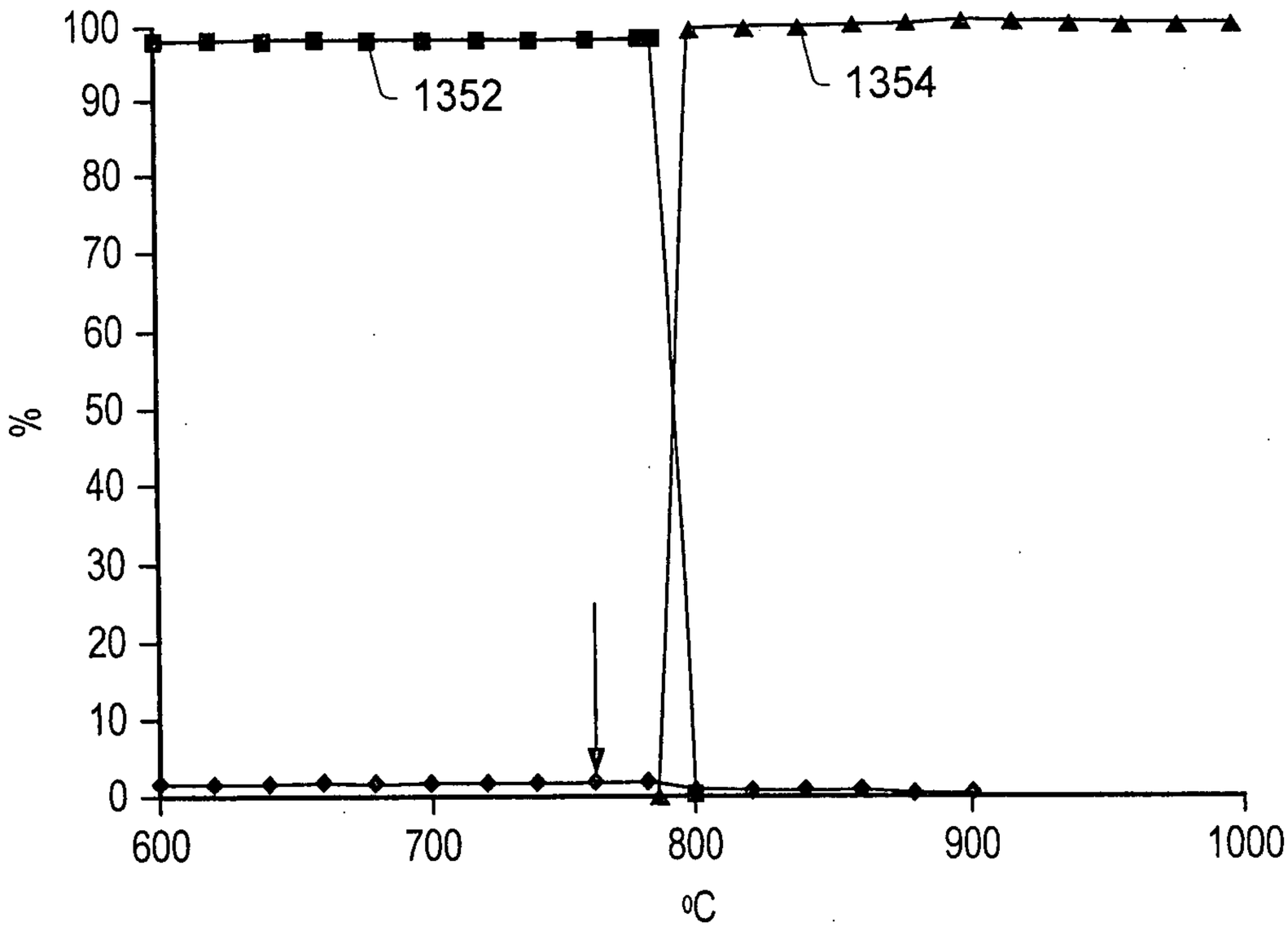


FIG. 236

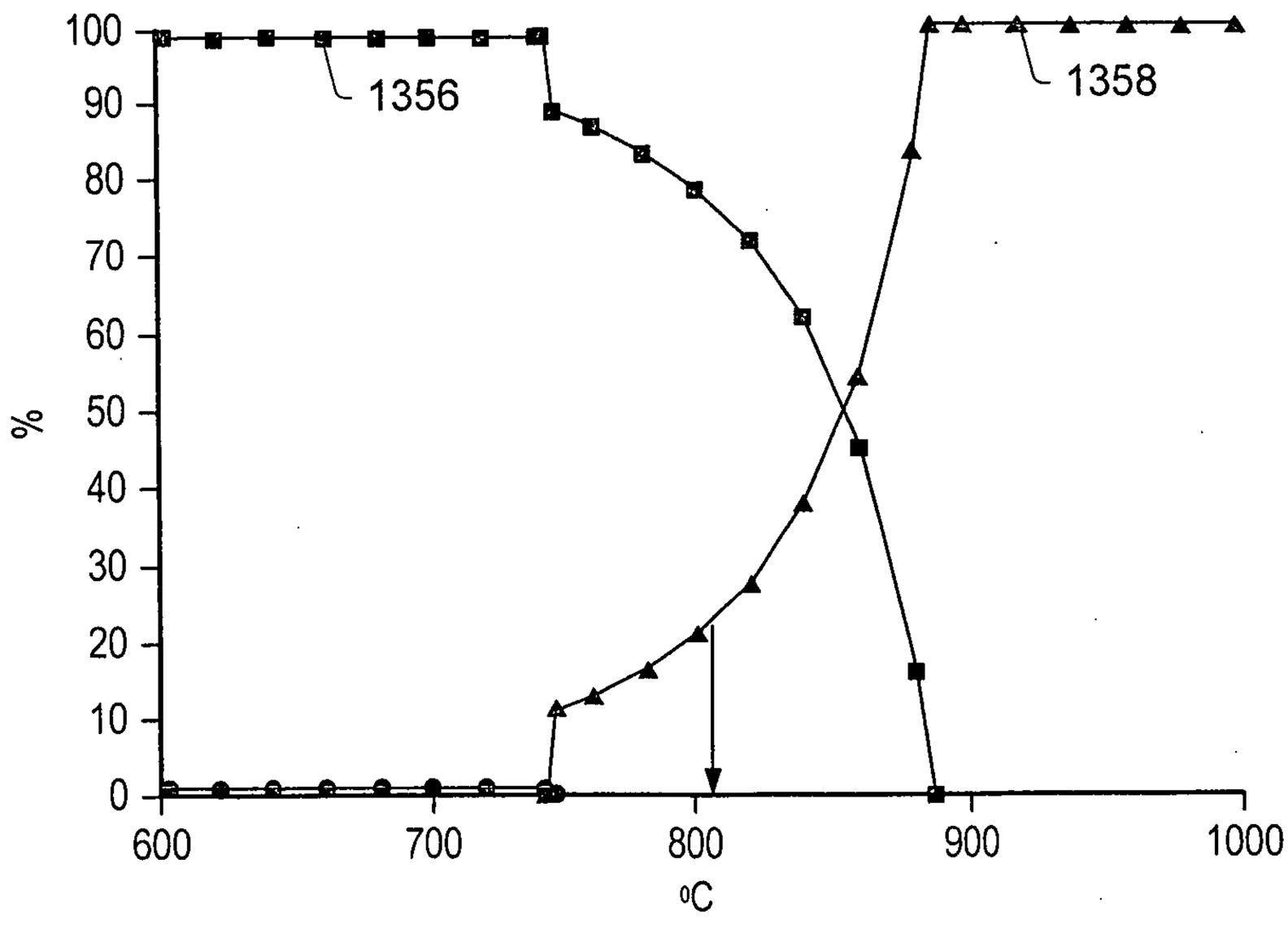


FIG. 237

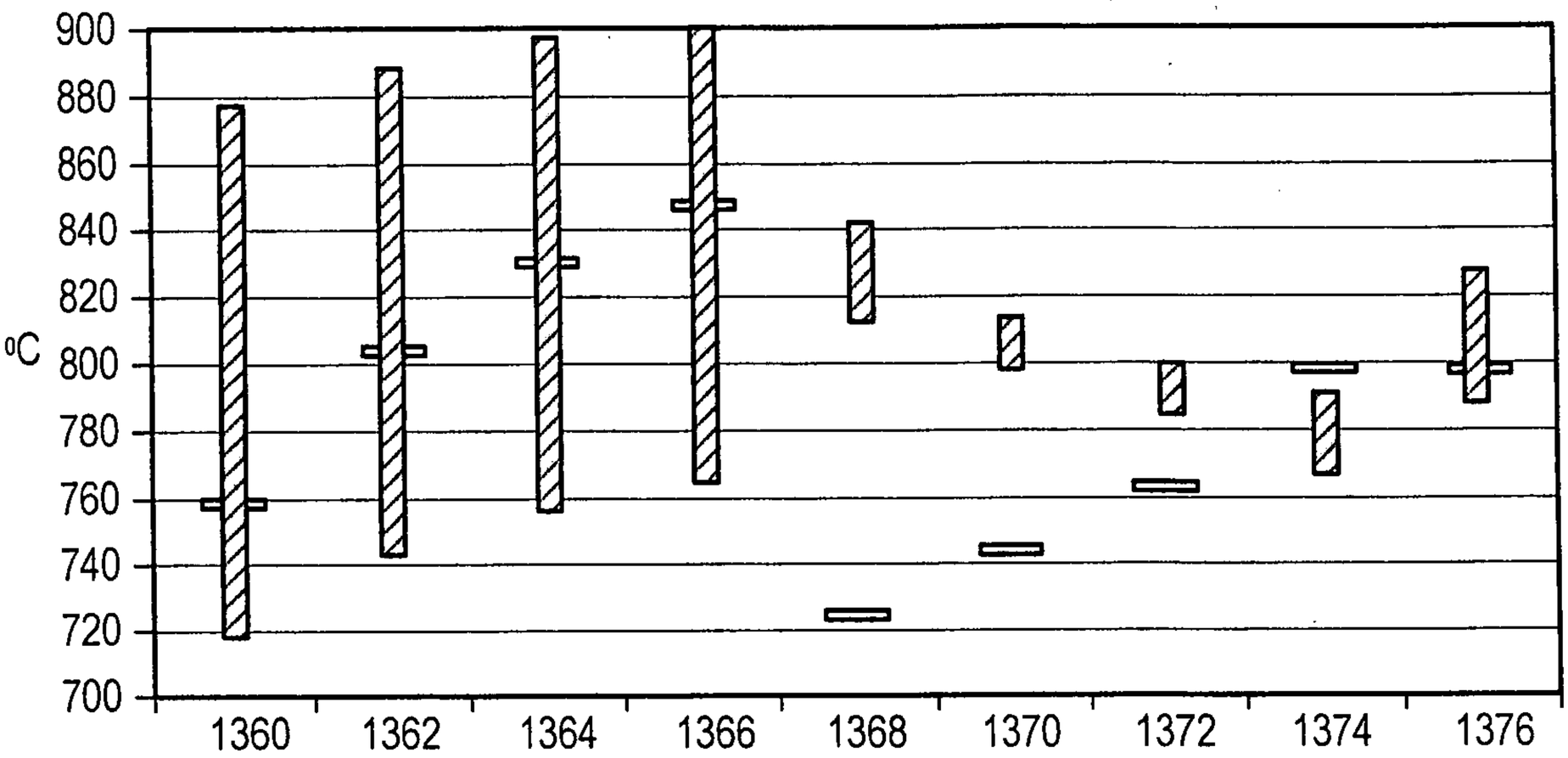


FIG. 238

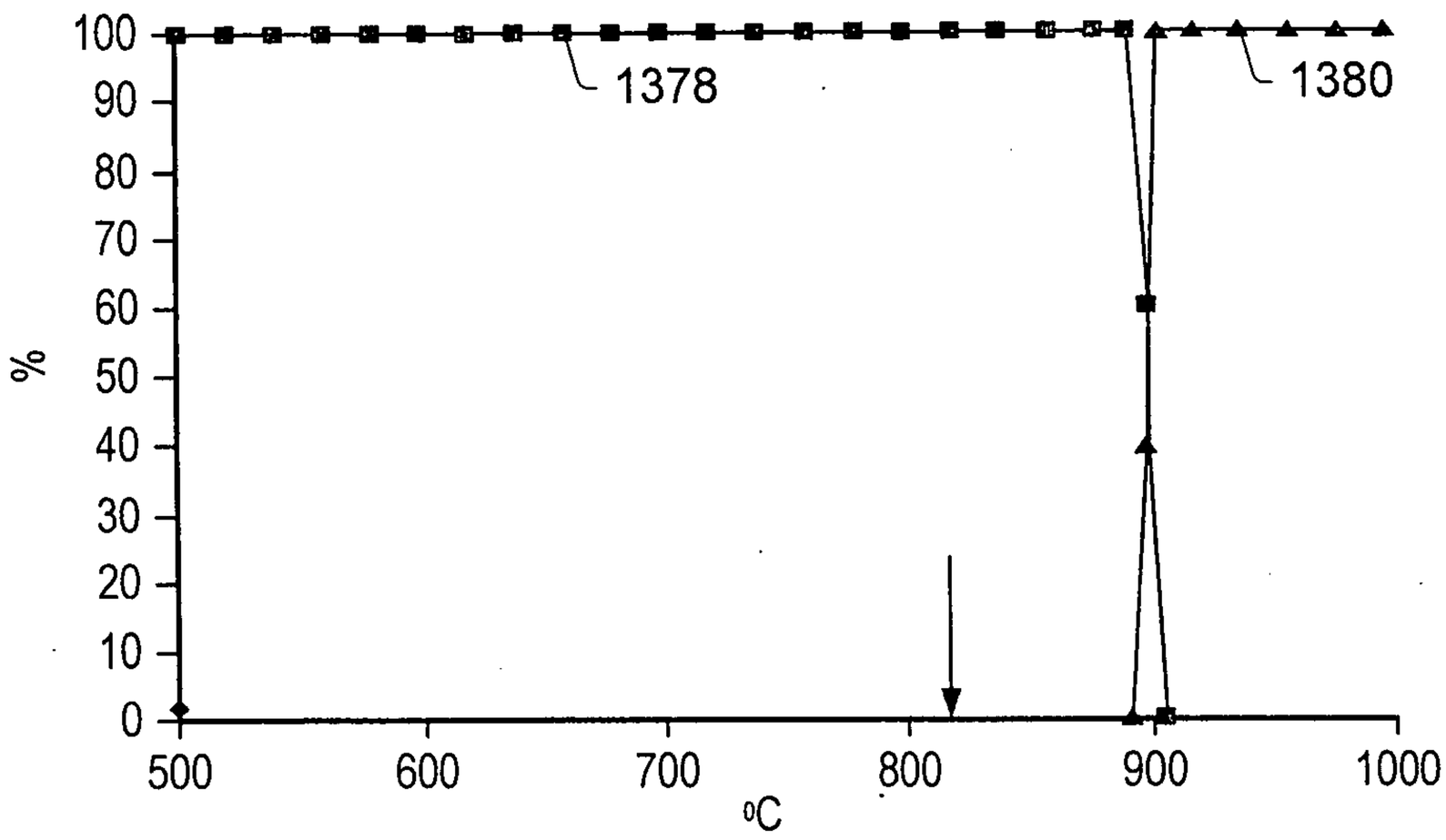


FIG. 239

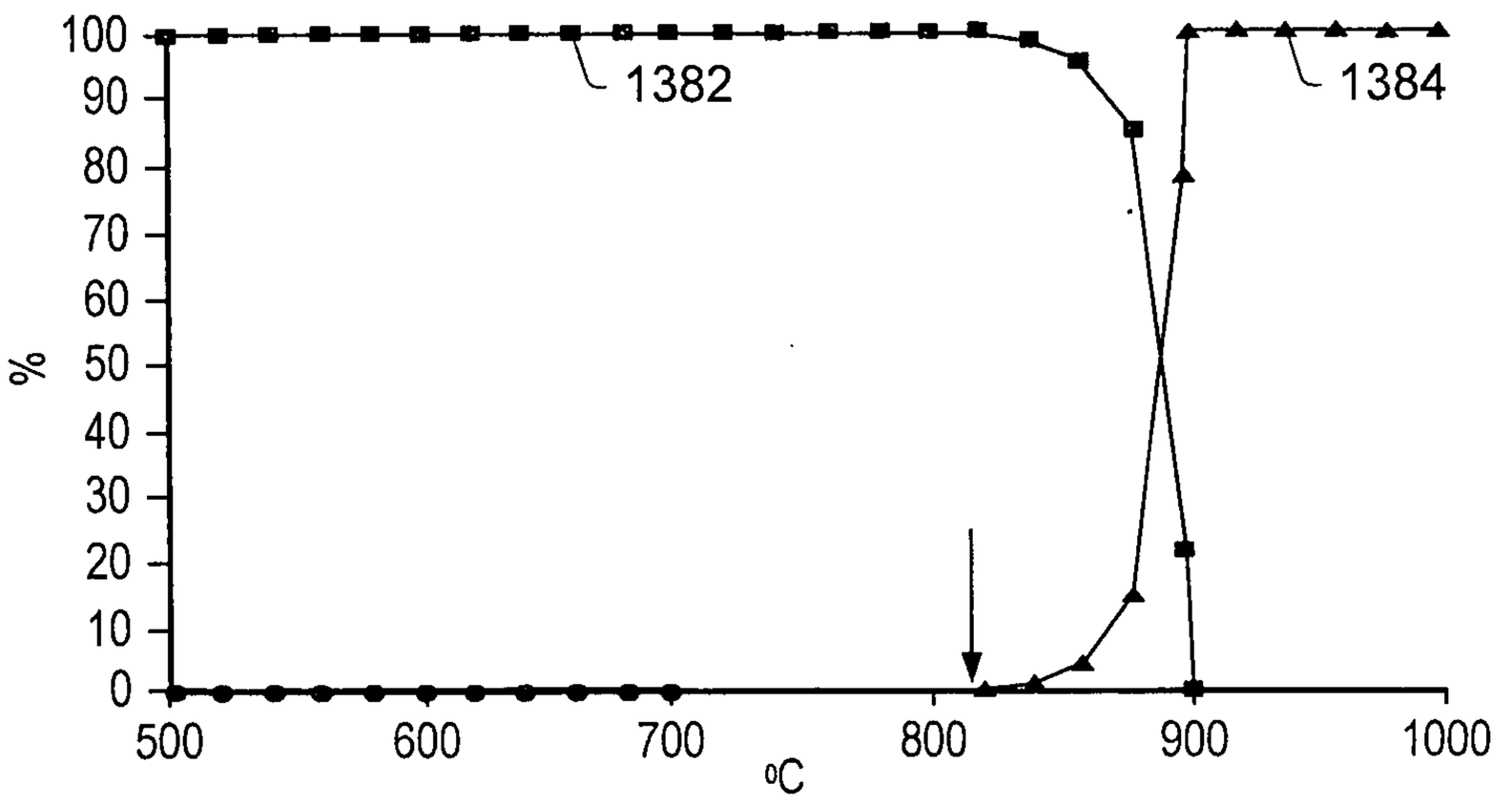


FIG. 240

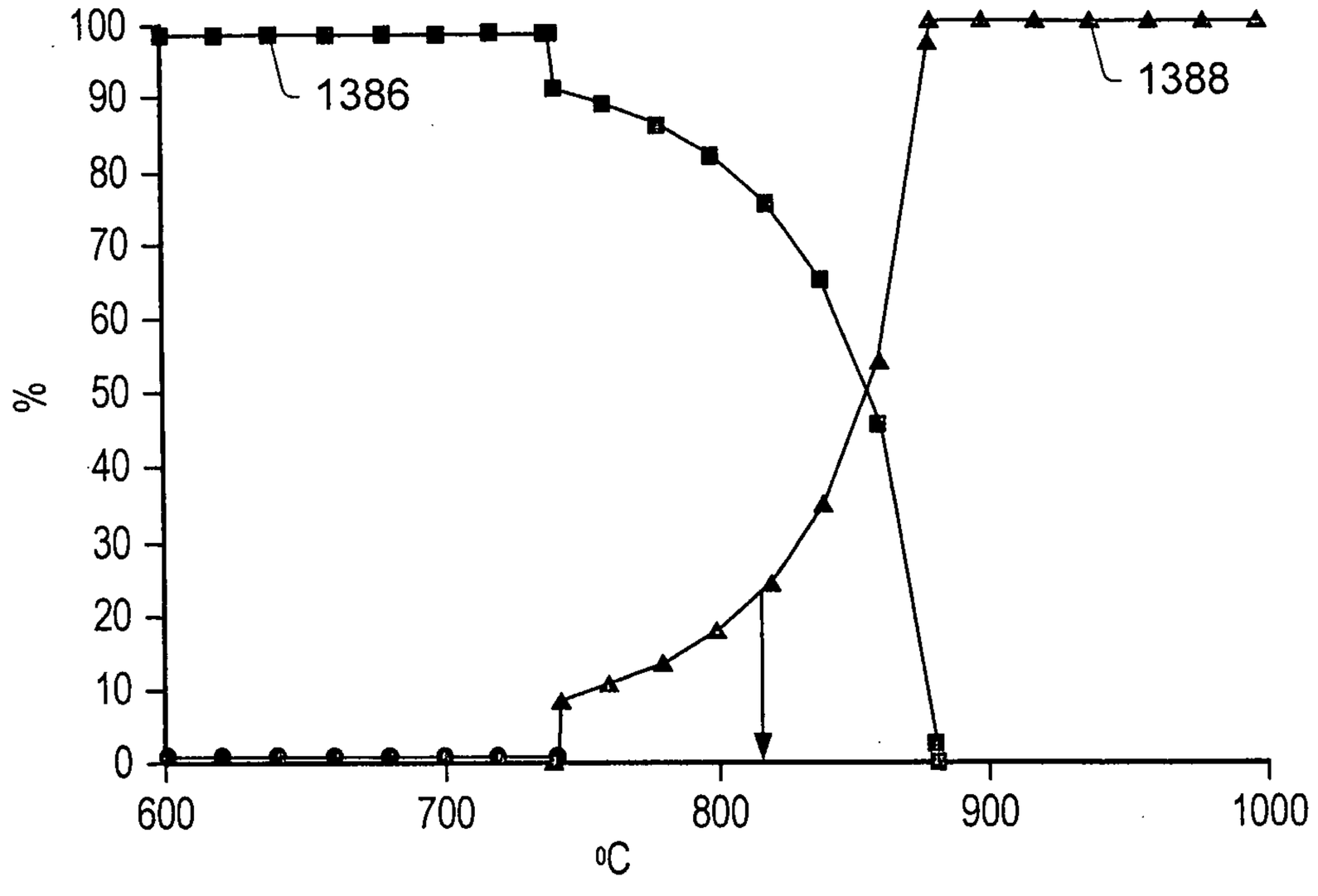


FIG. 241

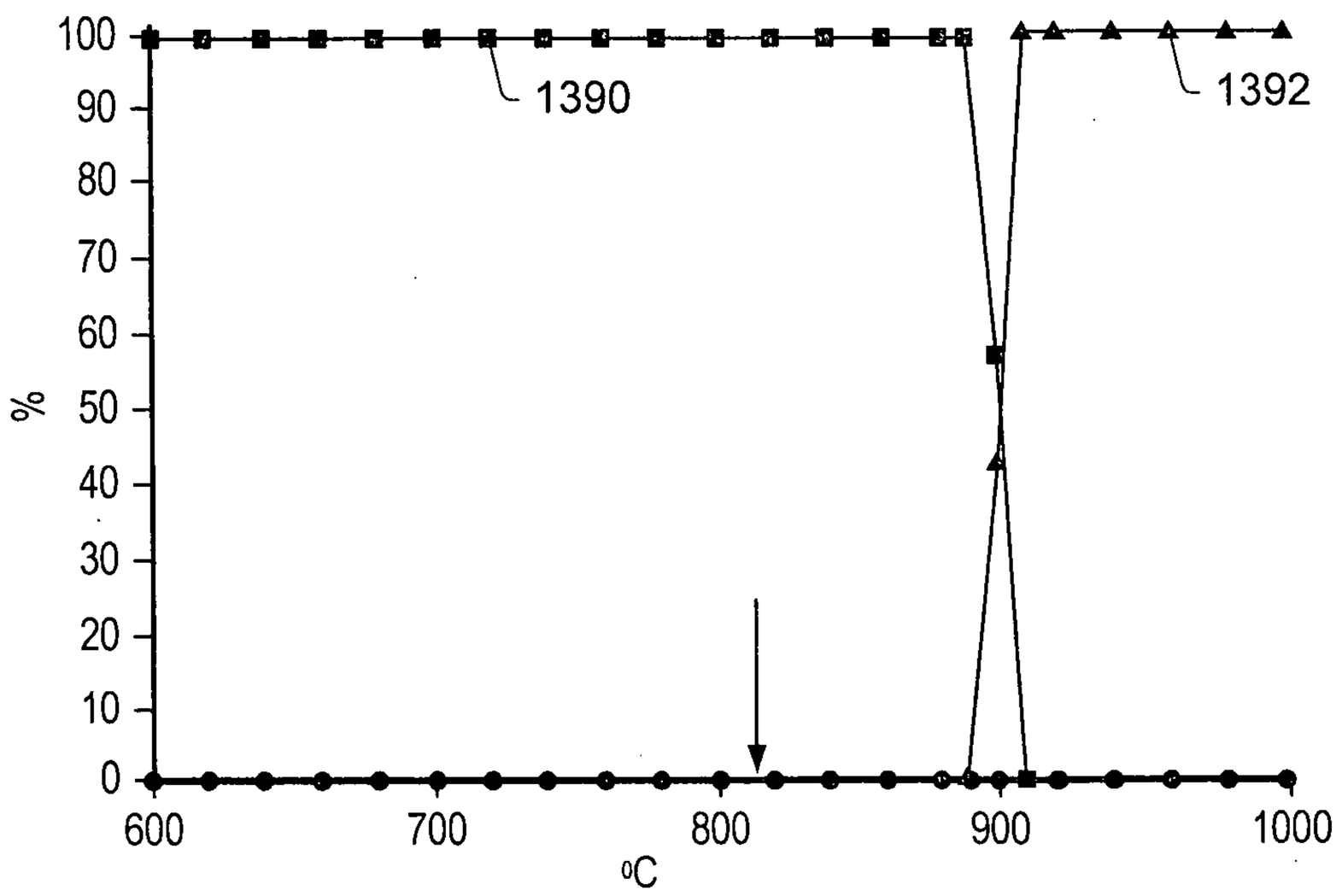


FIG. 242

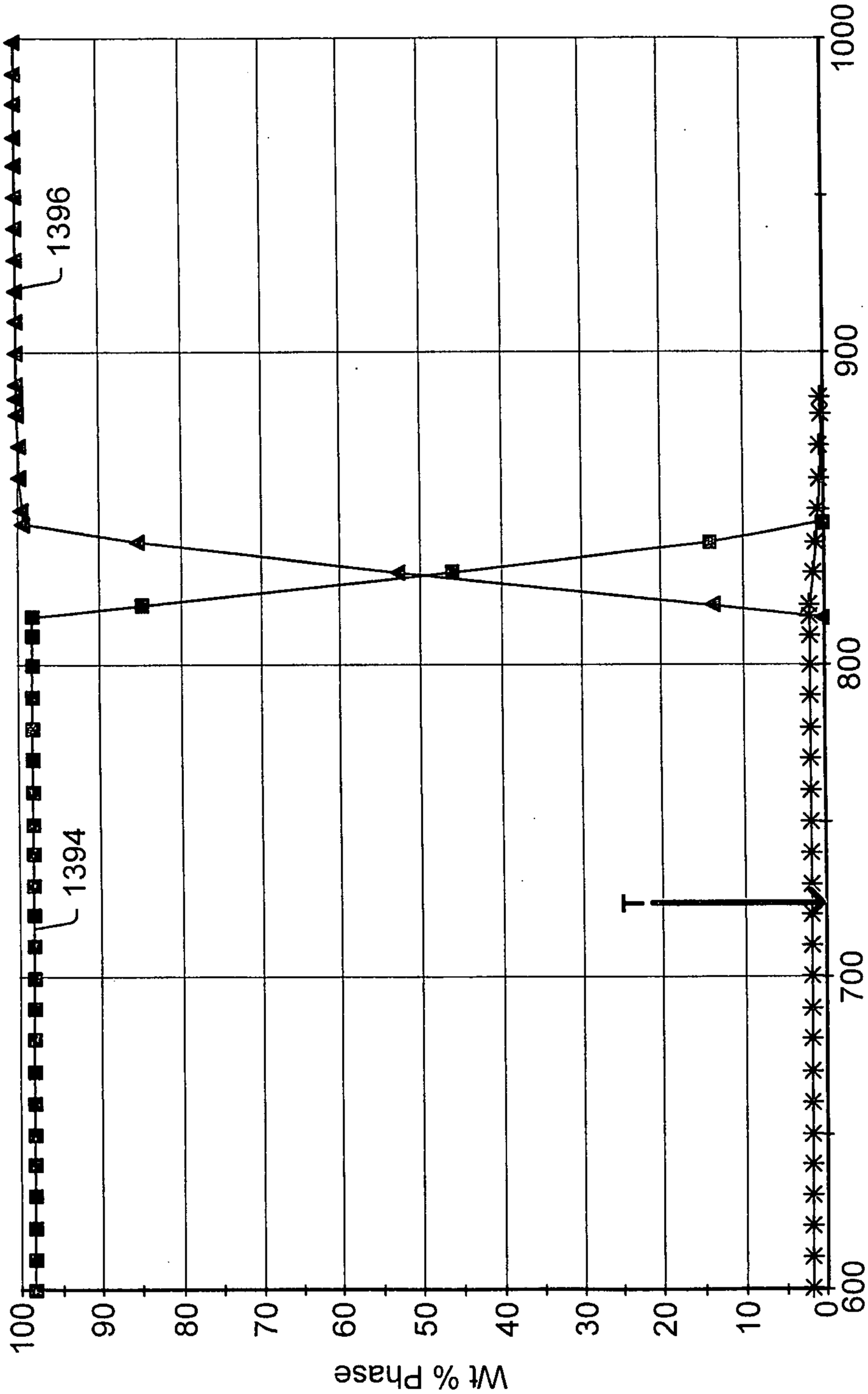

1396
1394
T
Wt % Phase
100
90
80
70
60
50
40
30
20
10
0
1000
900
800
700
600
Temperature (C)

FIG. 243

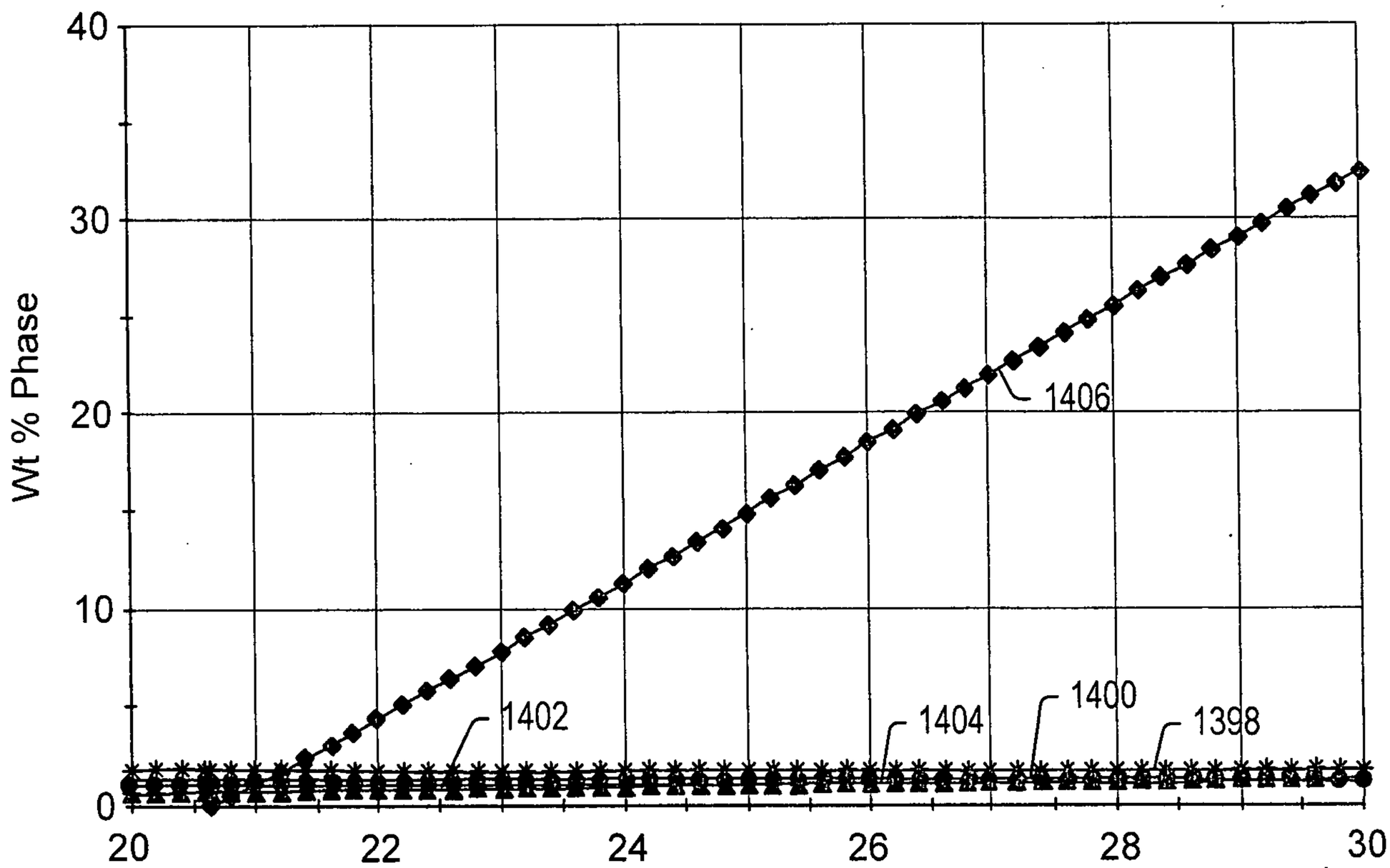


FIG. 244

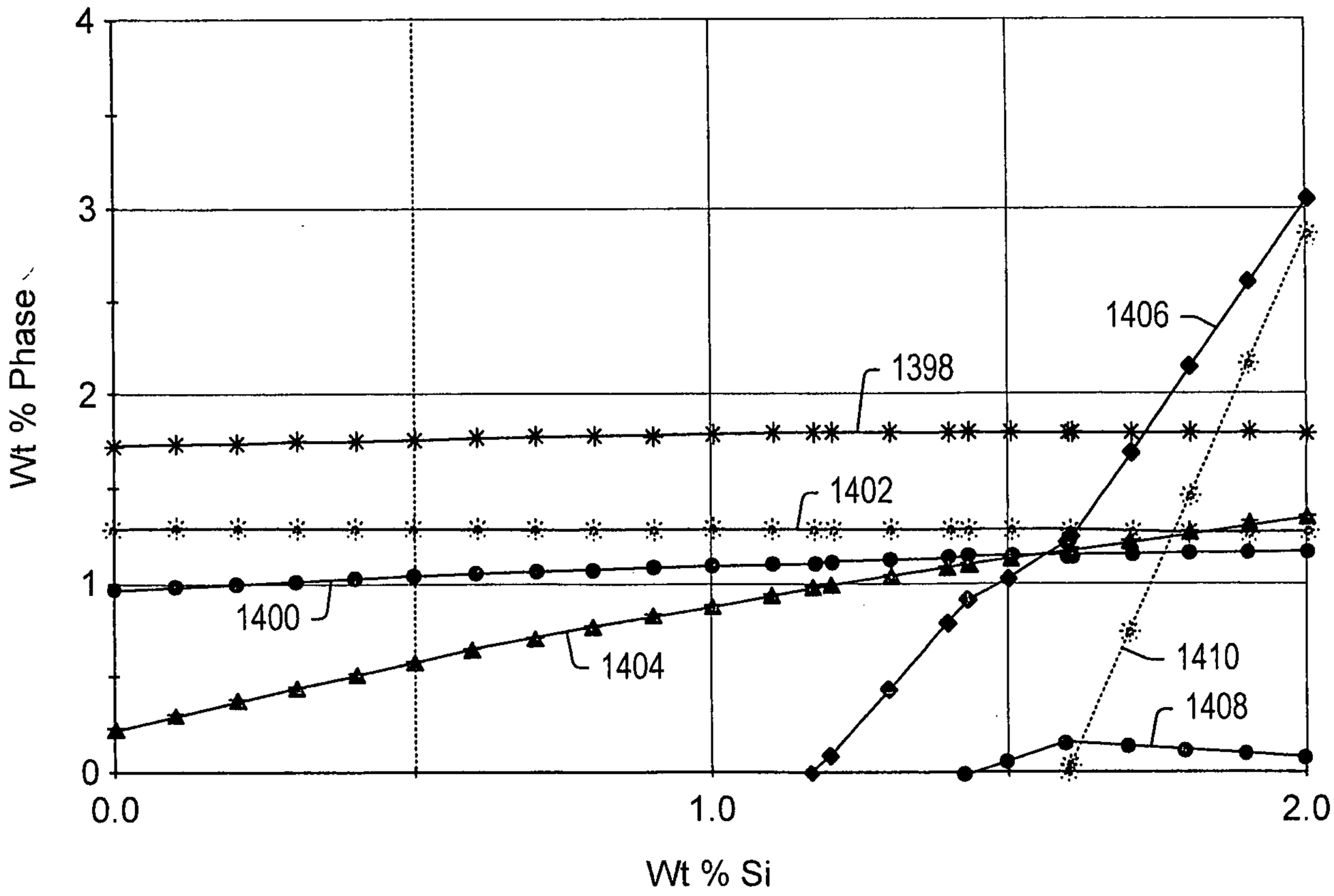


FIG. 245

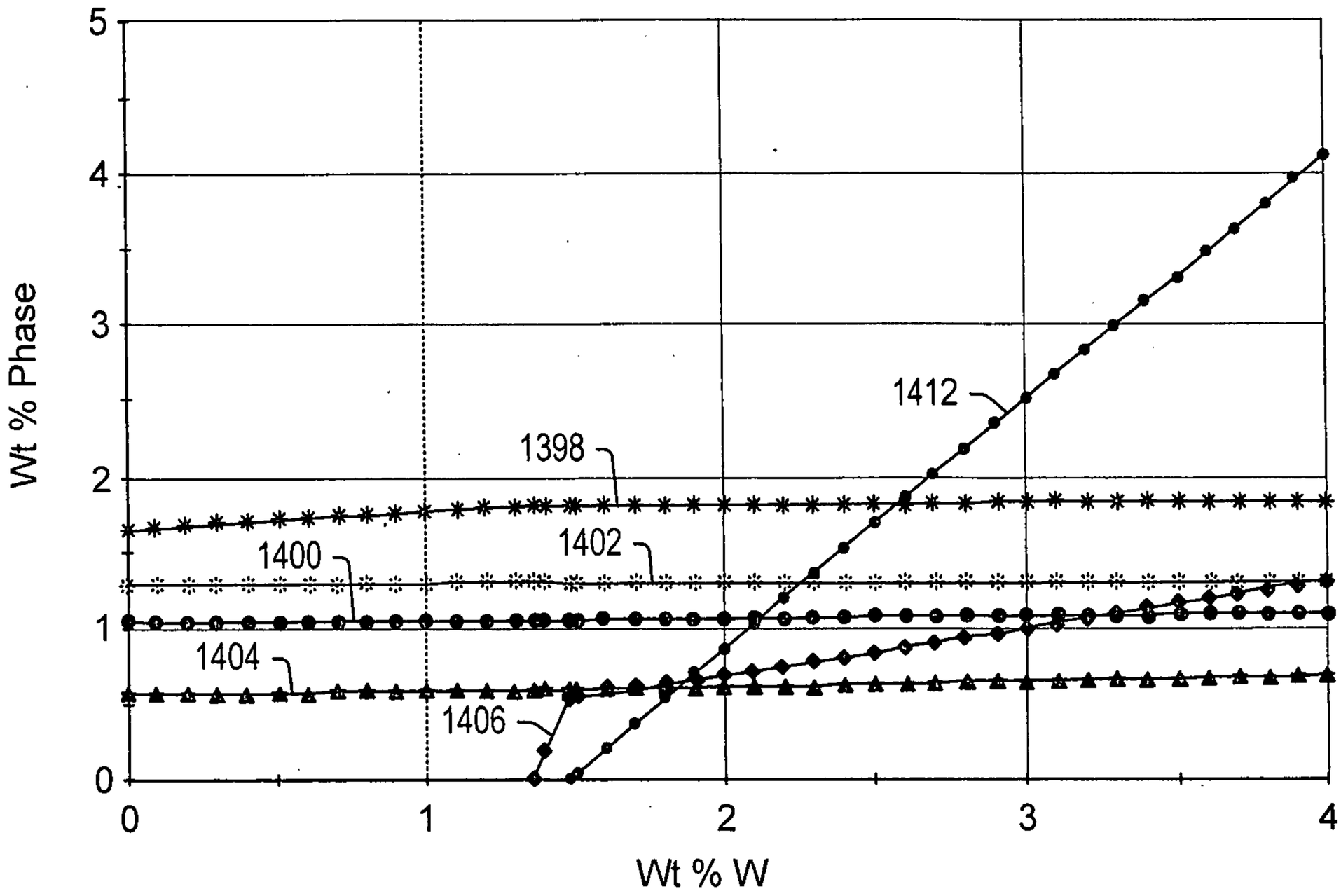


FIG. 246

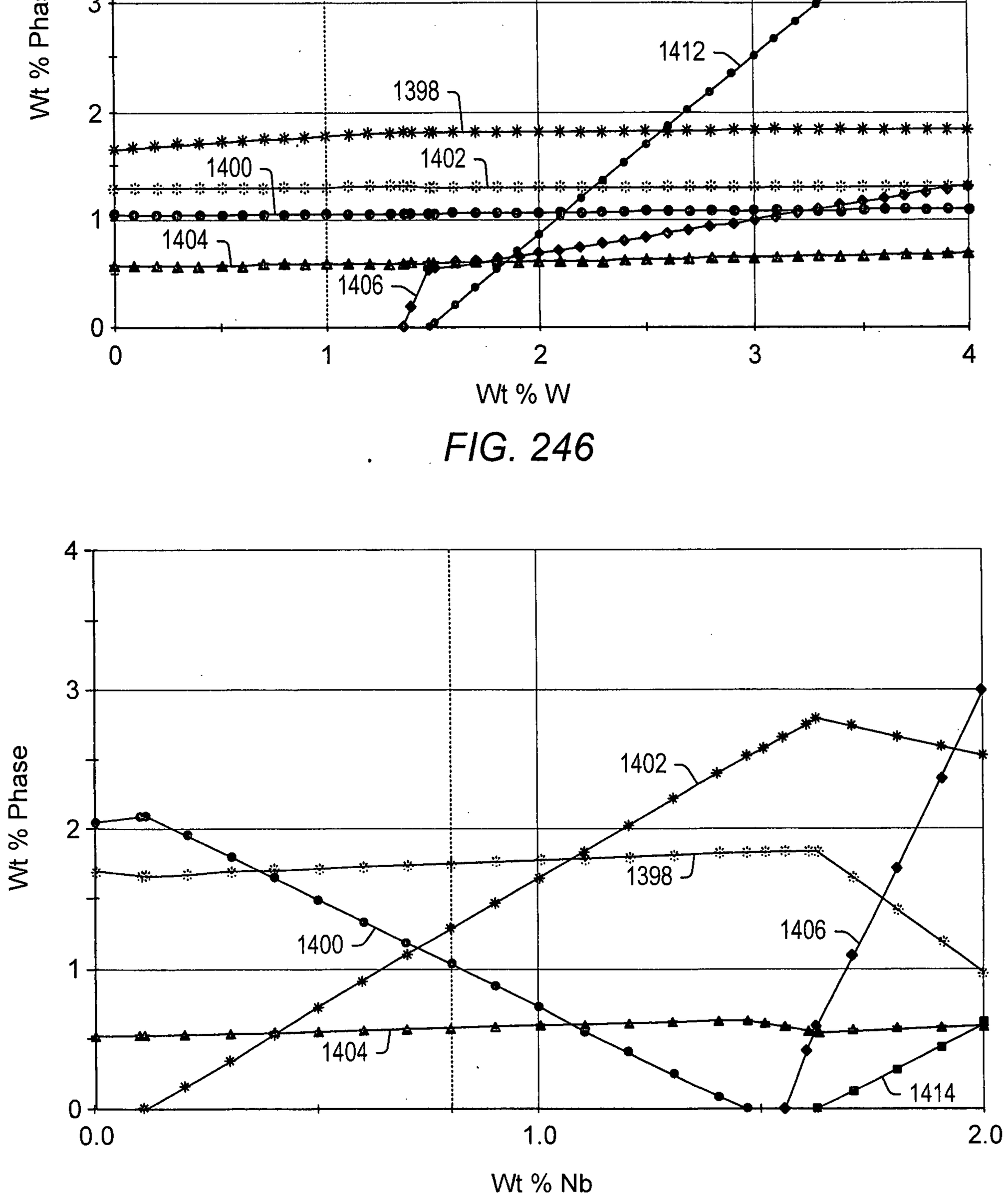


FIG. 247

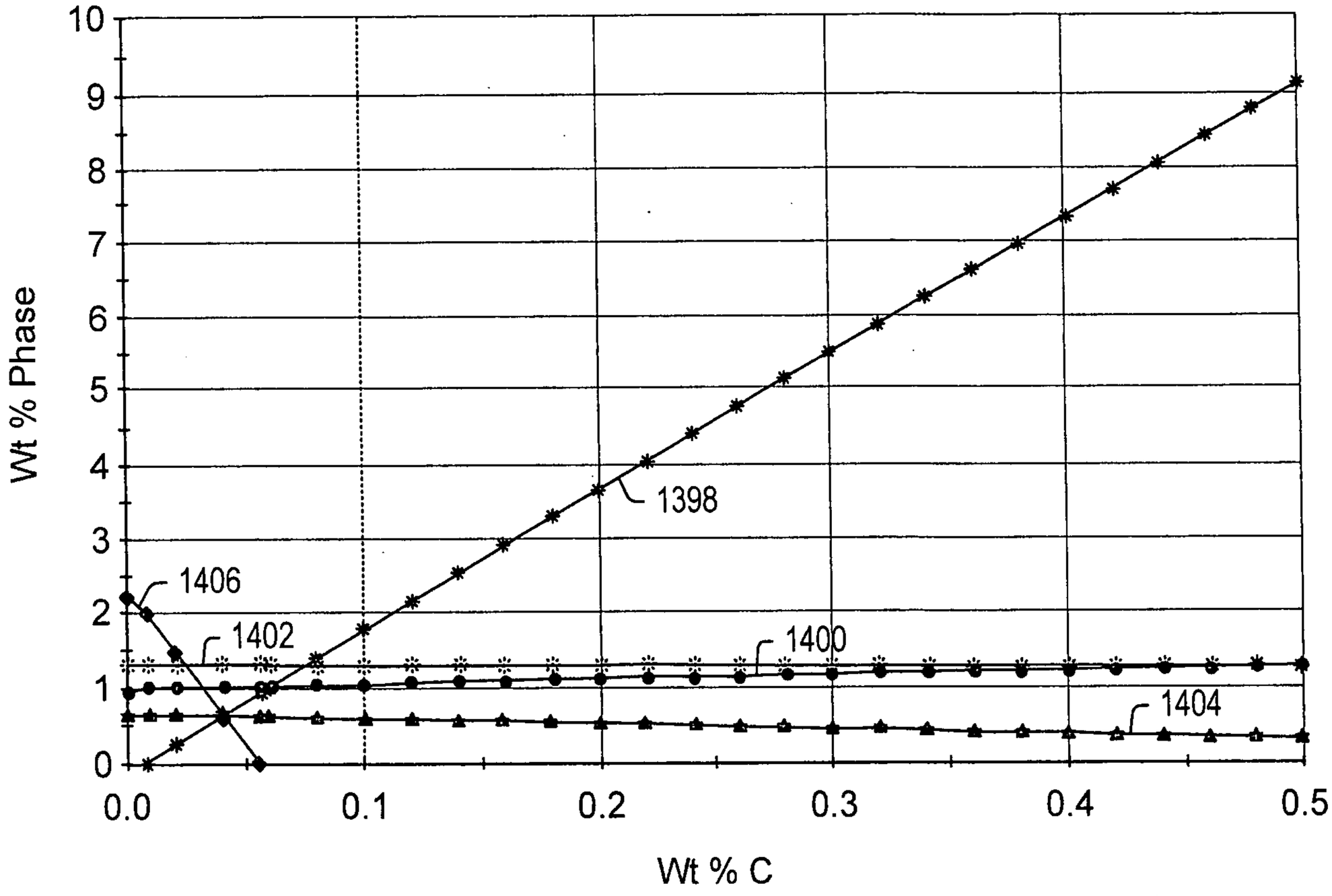


FIG. 248

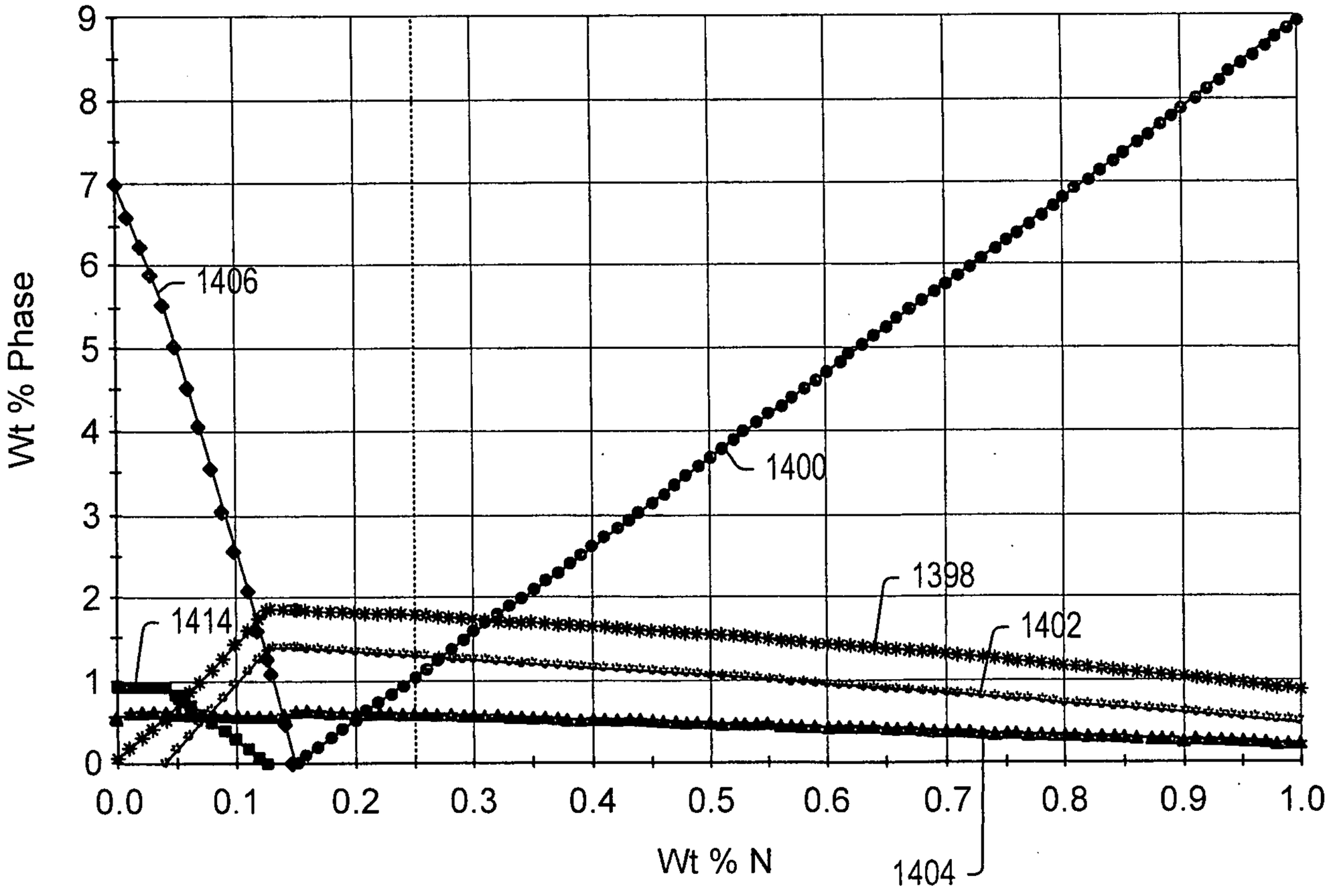


FIG. 249

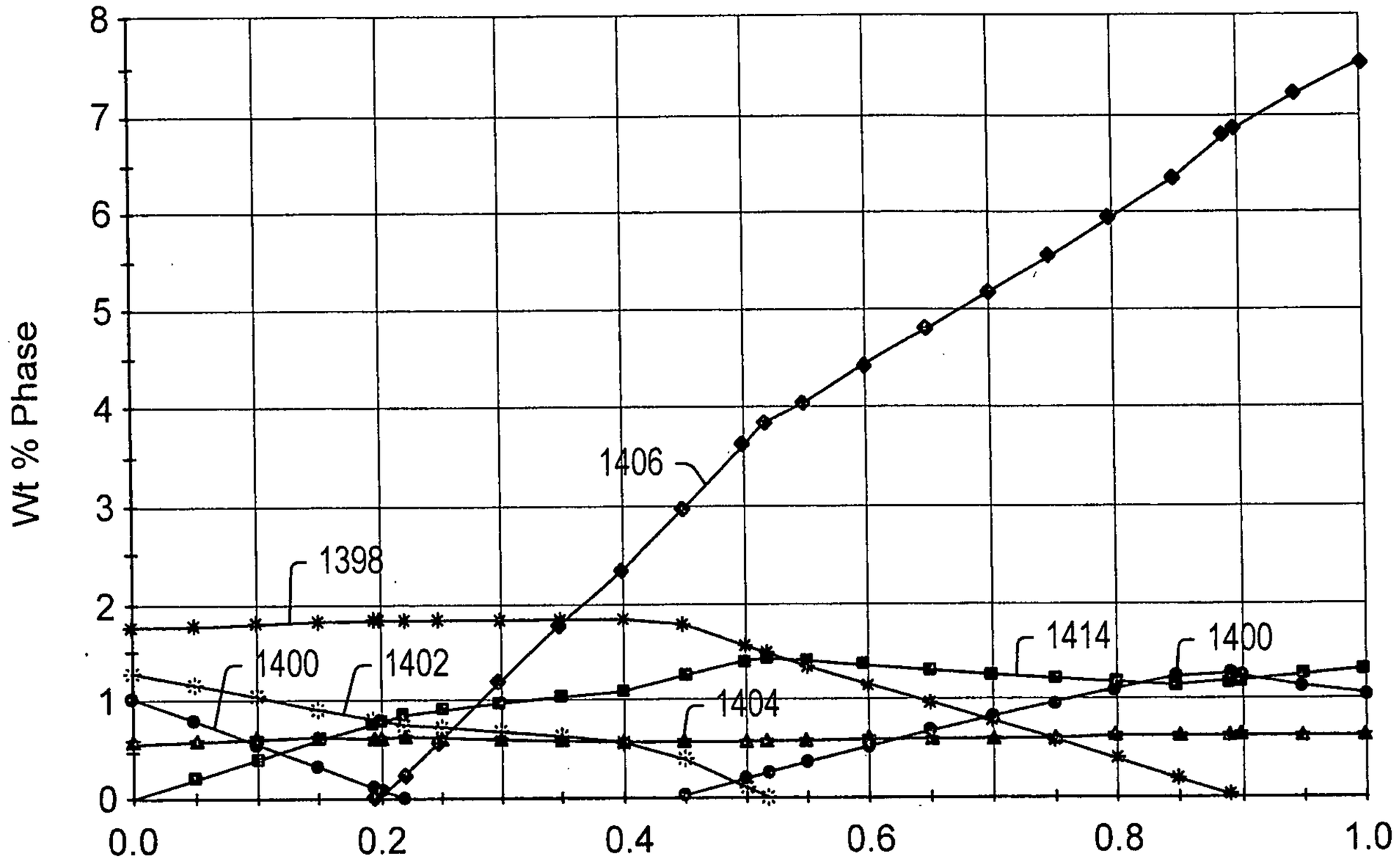


FIG. 250

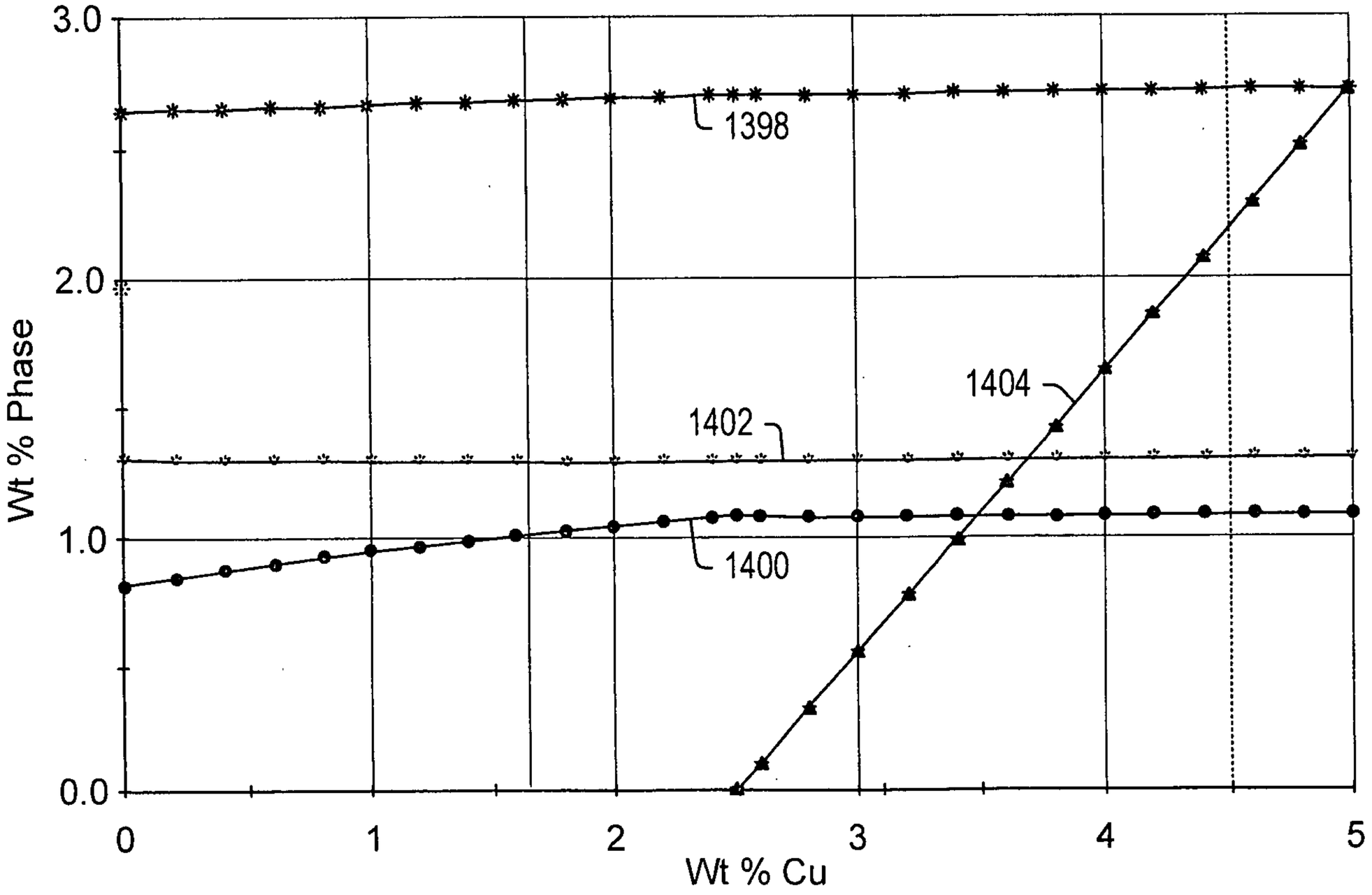


FIG. 251

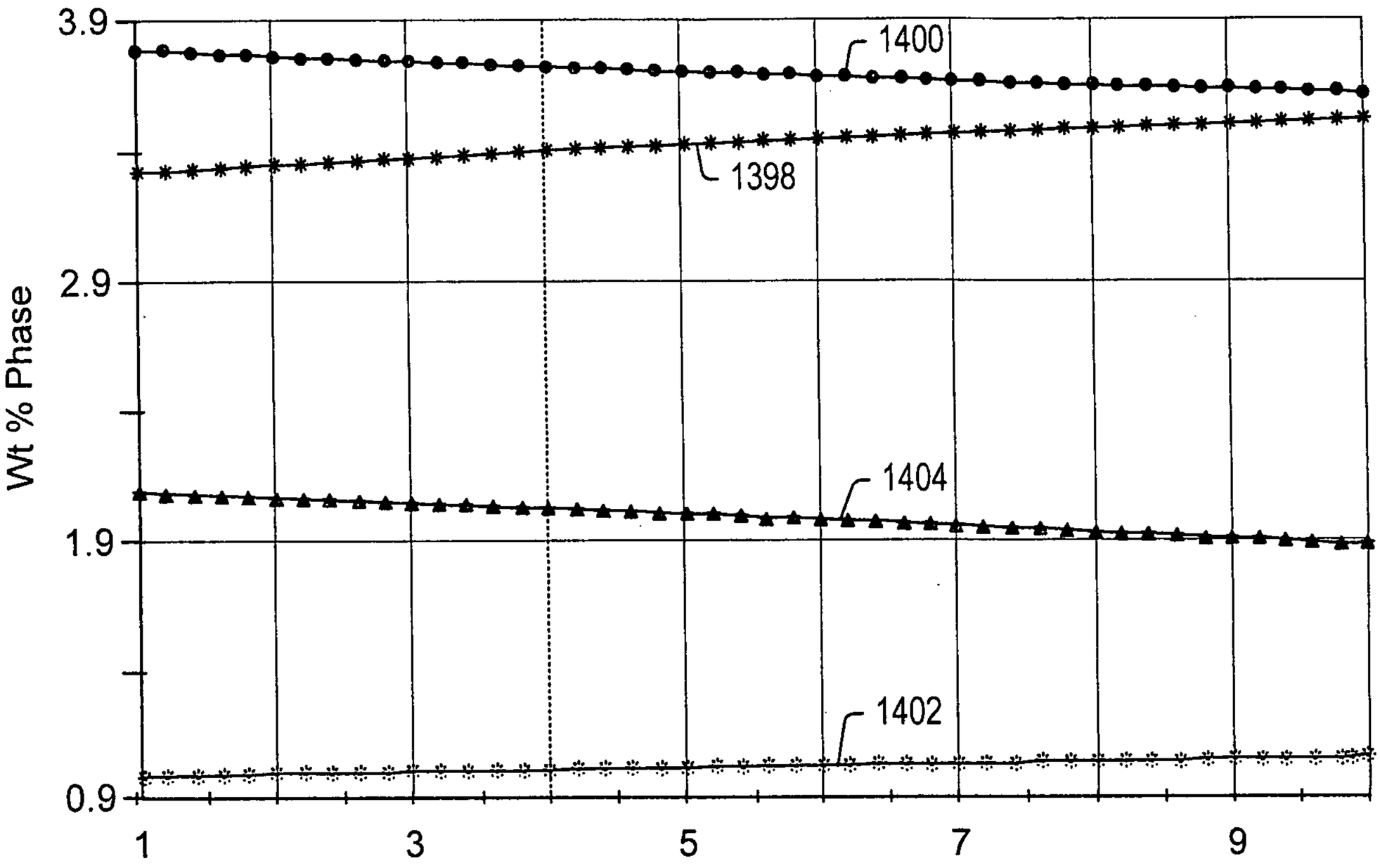


FIG. 252

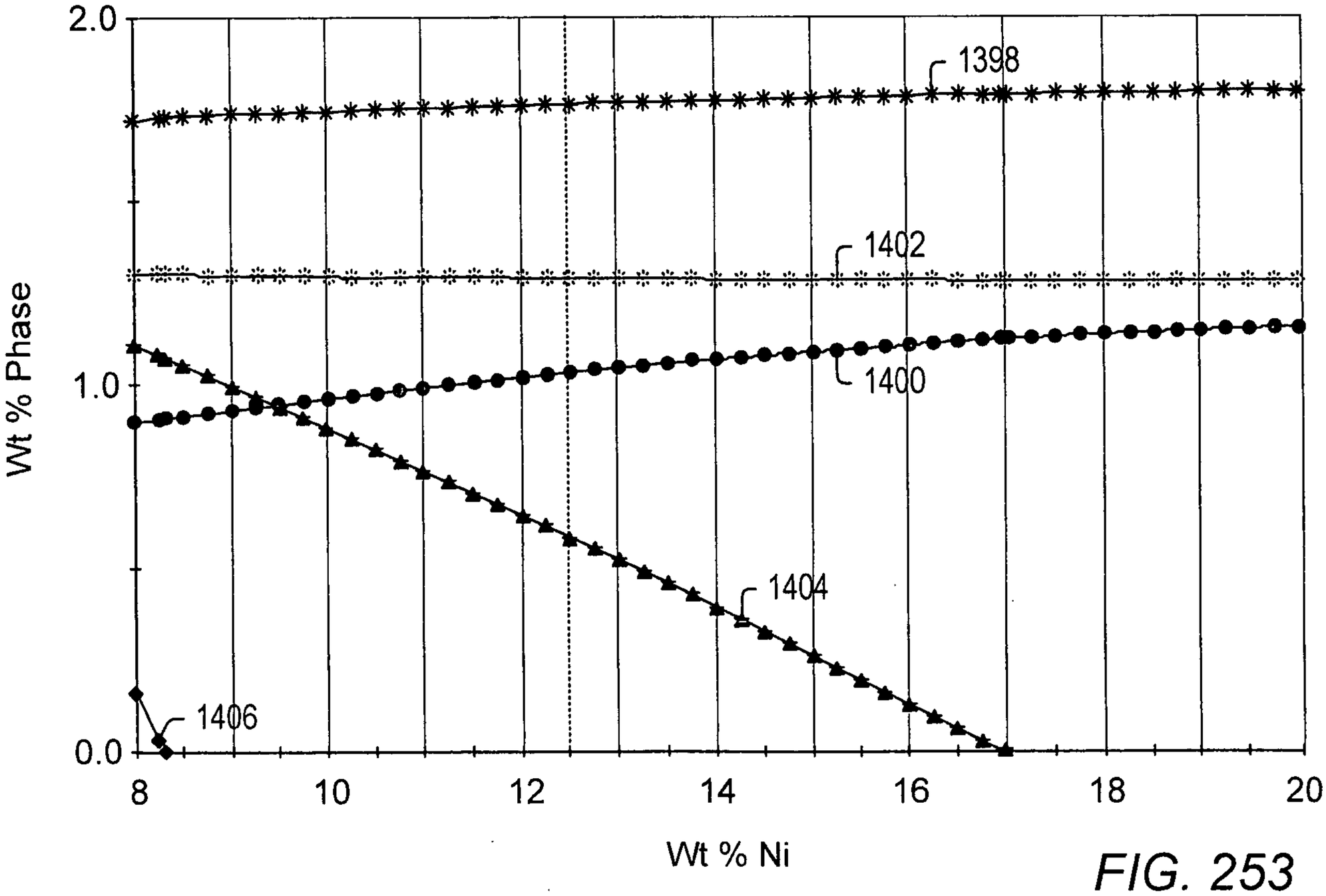


FIG. 253

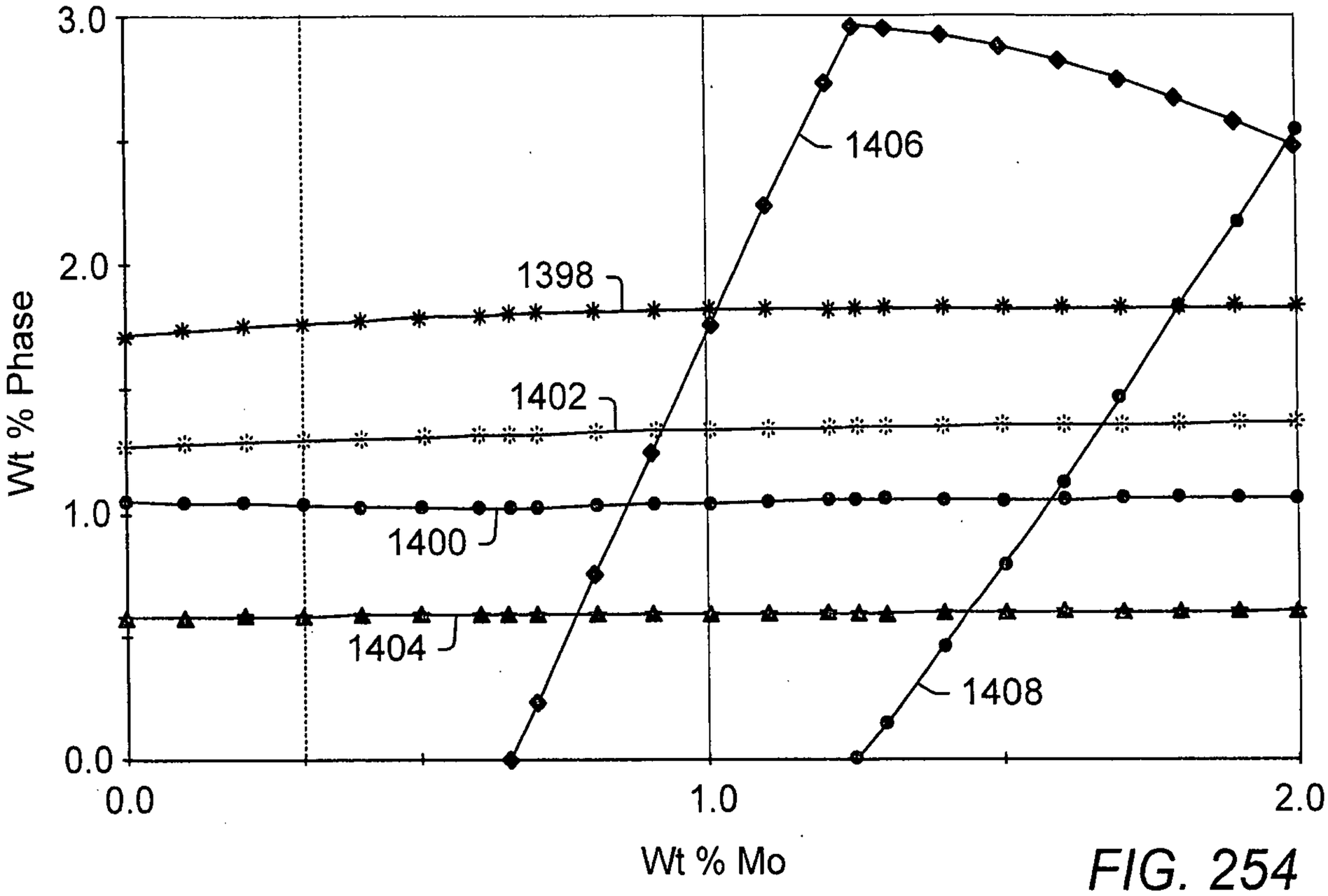


FIG. 254

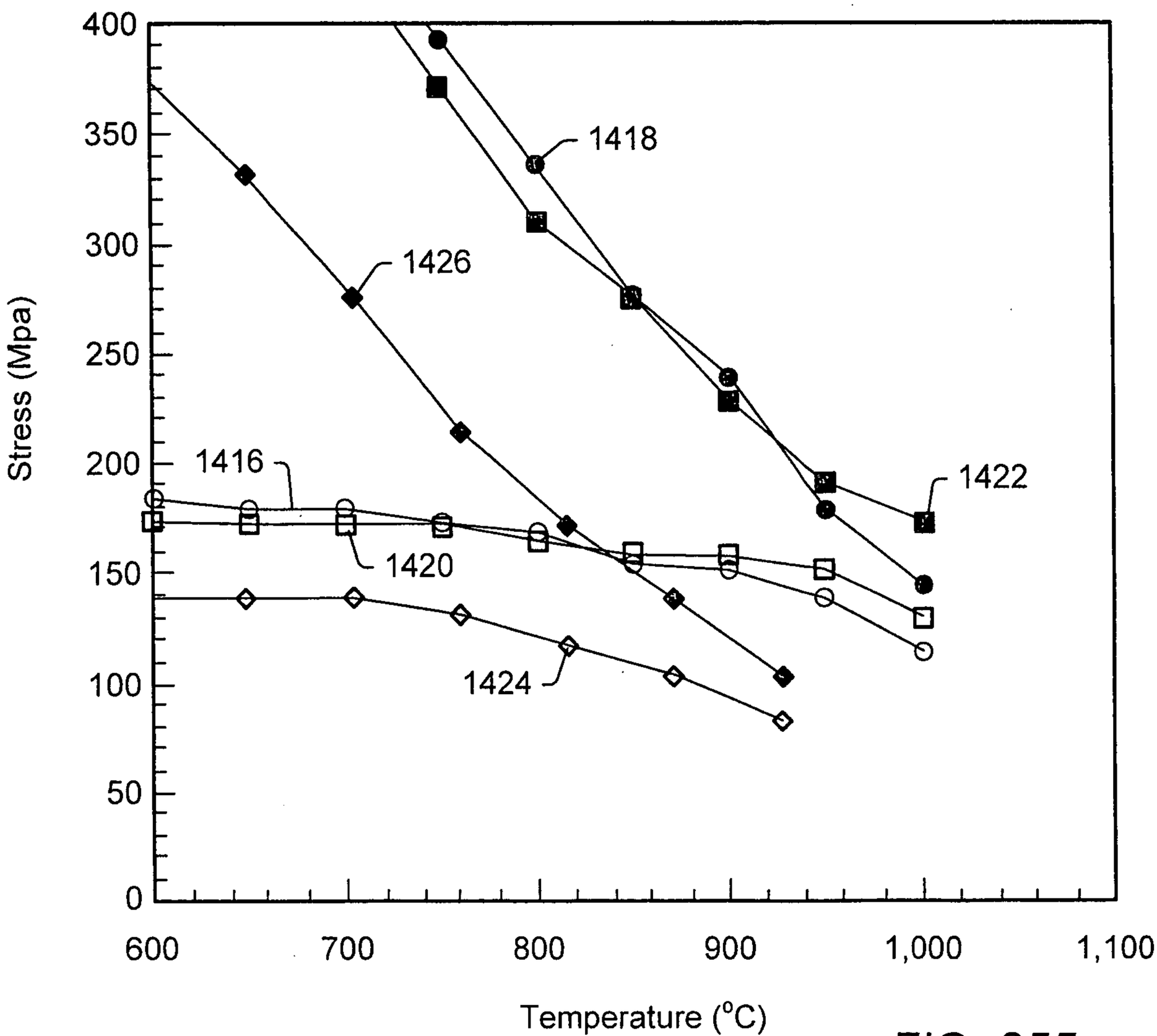


FIG. 255

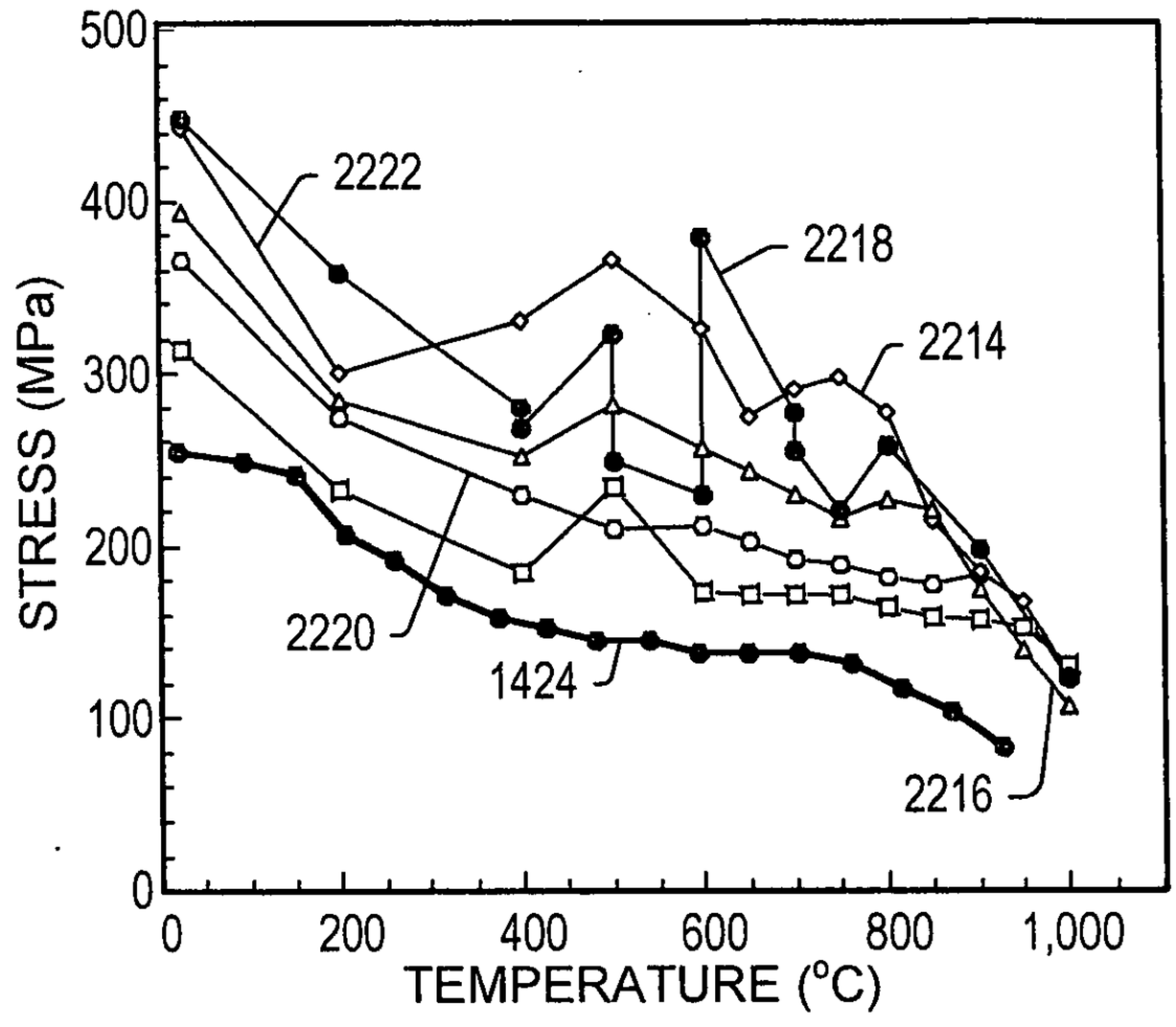


FIG. 255B

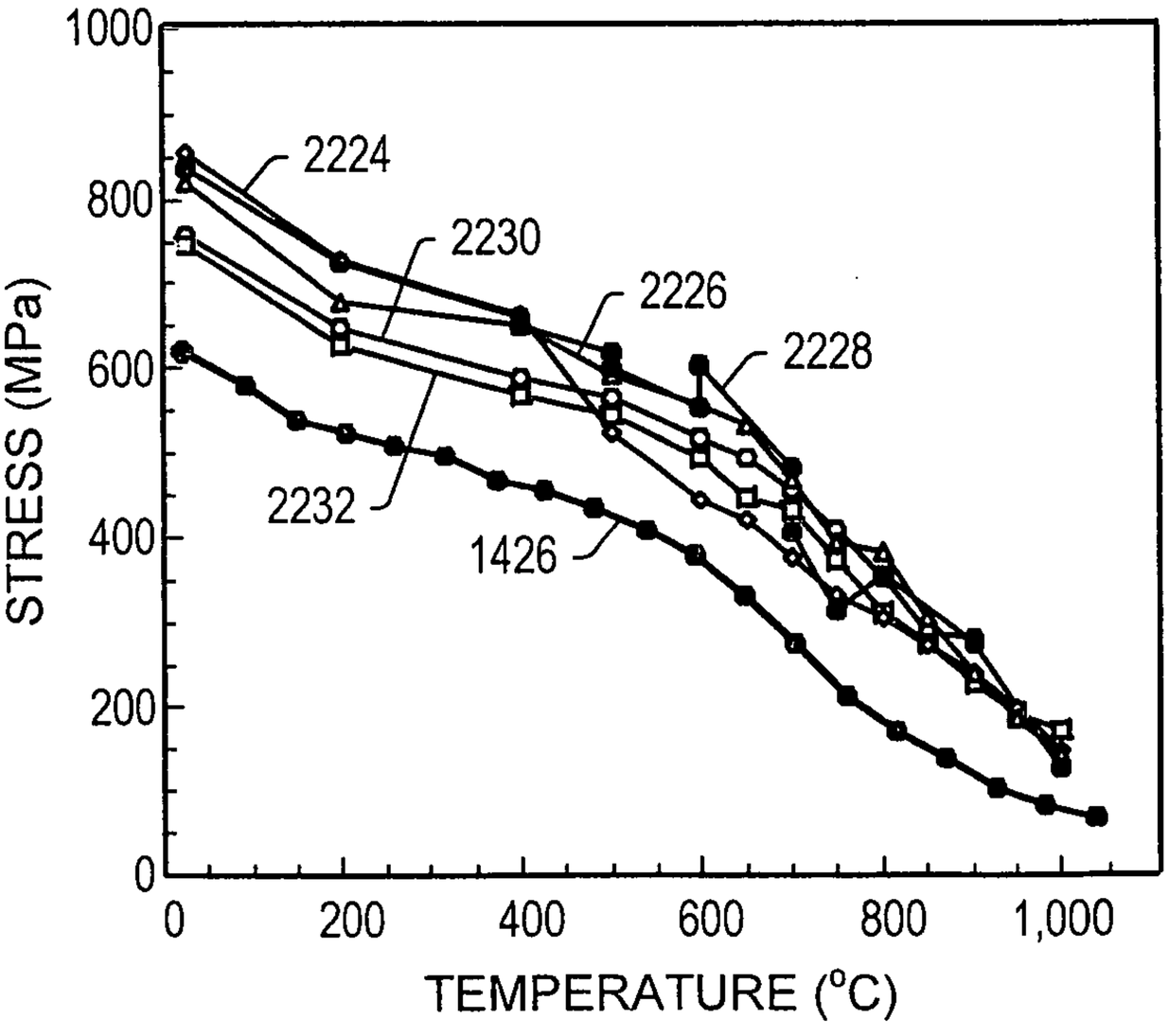


FIG. 255C

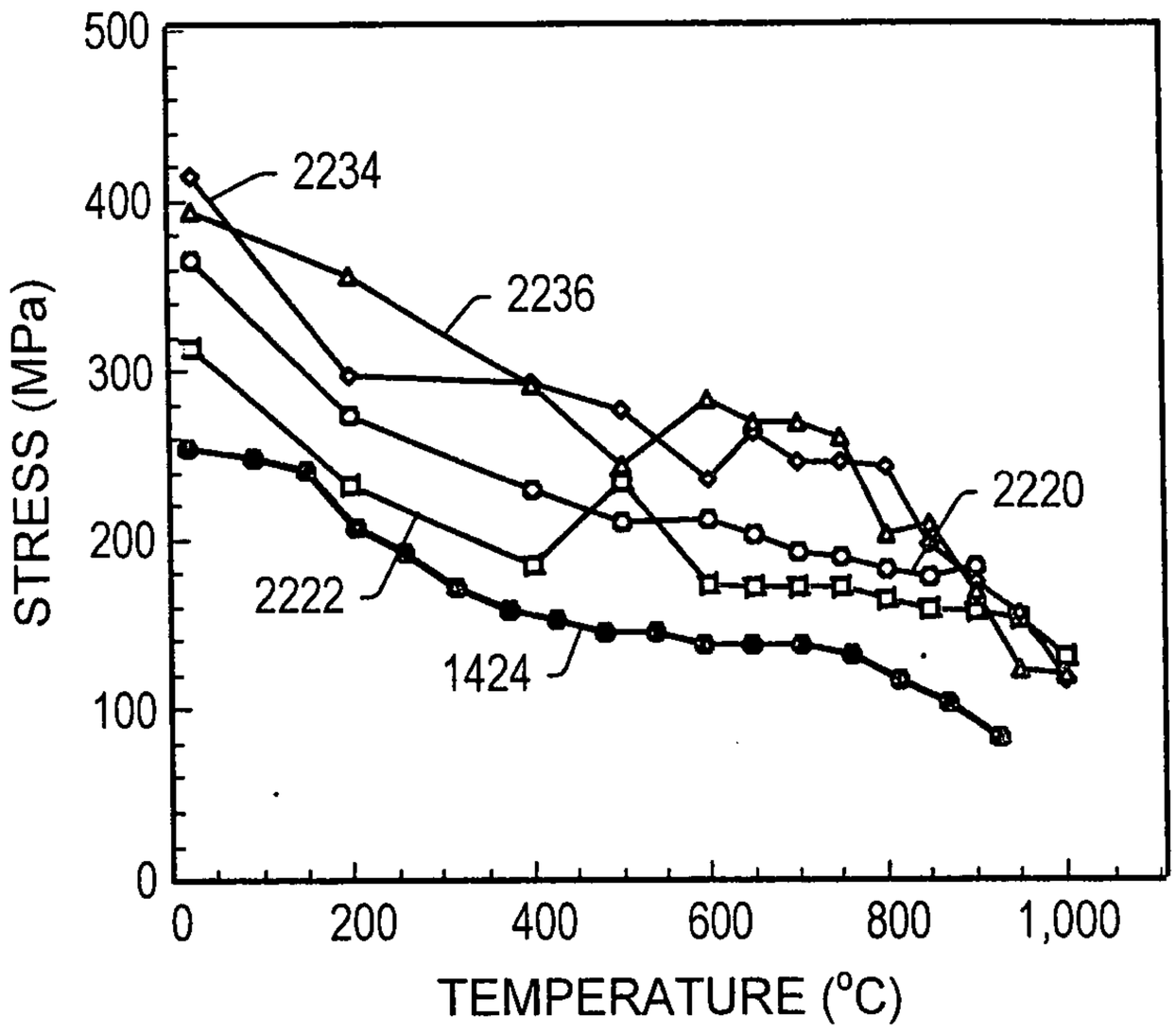


FIG. 255D

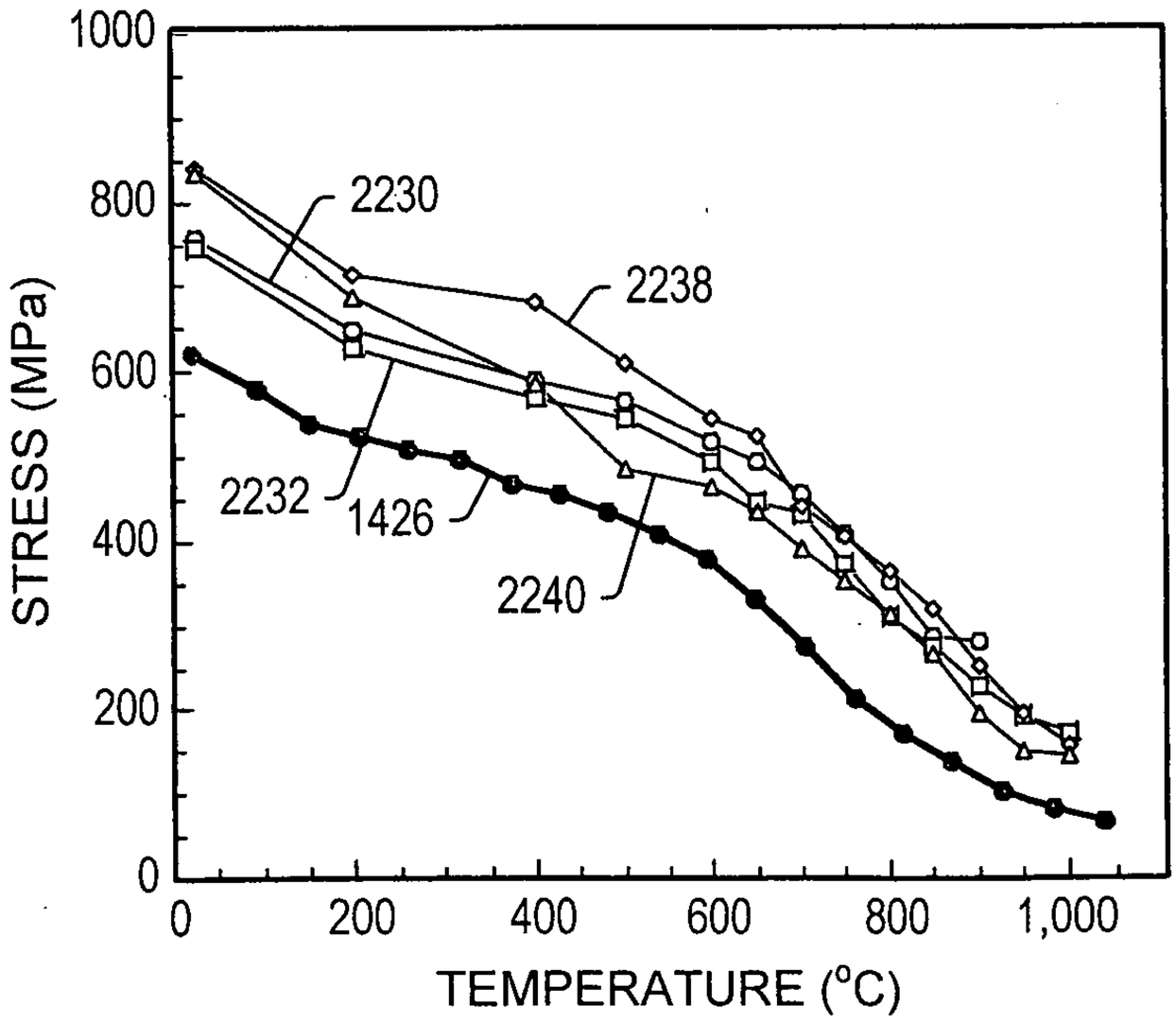


FIG. 255E

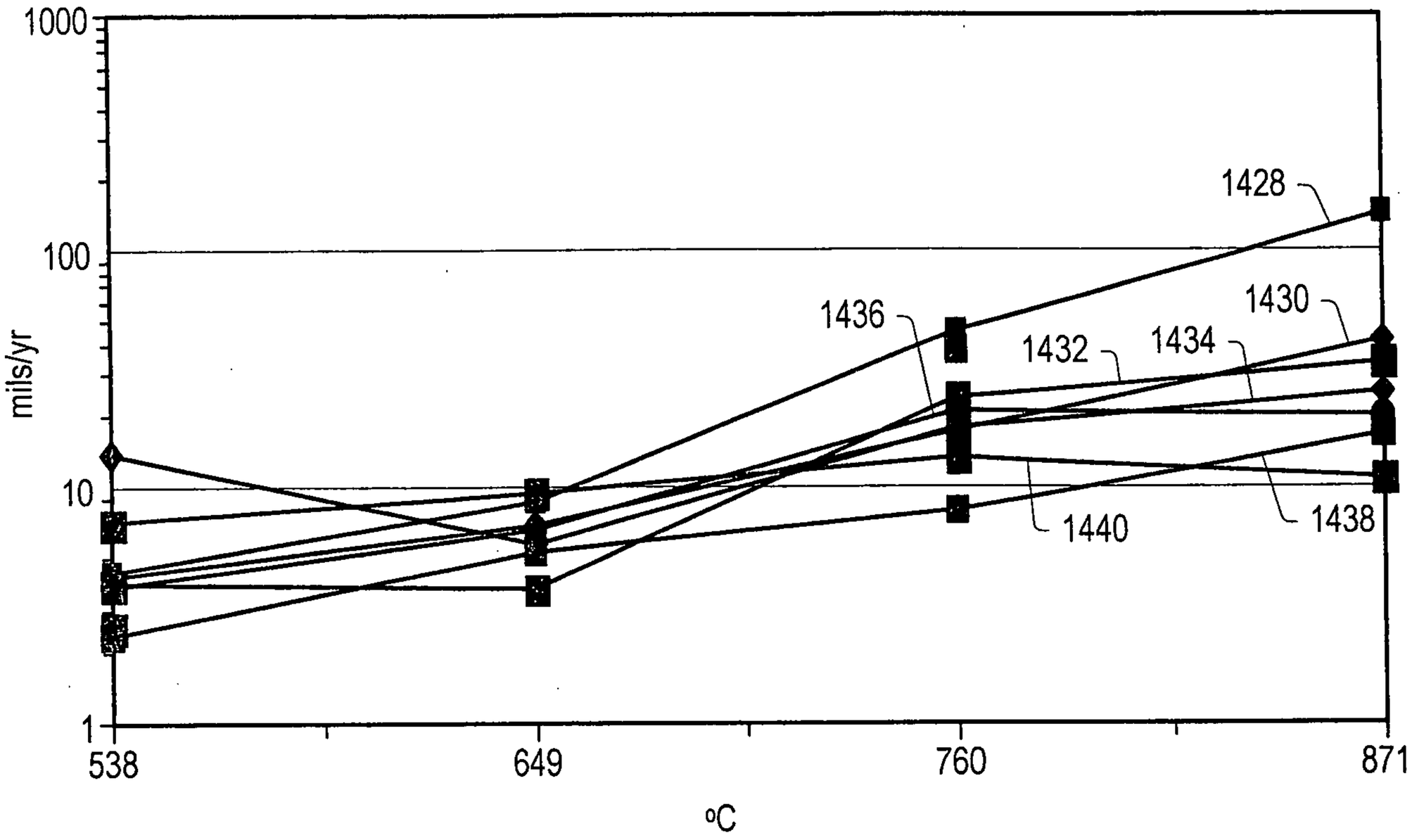


FIG. 256

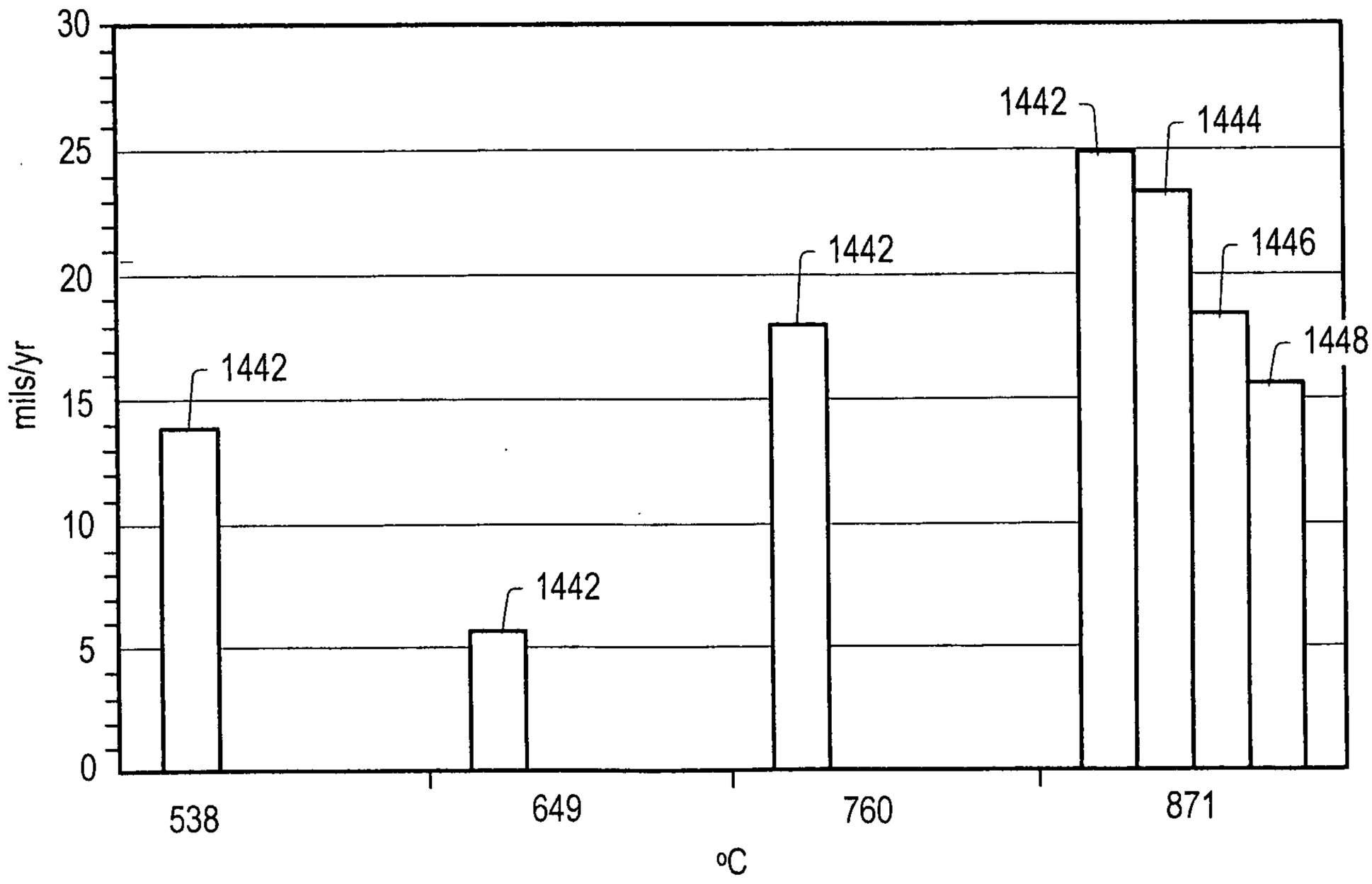


FIG. 257

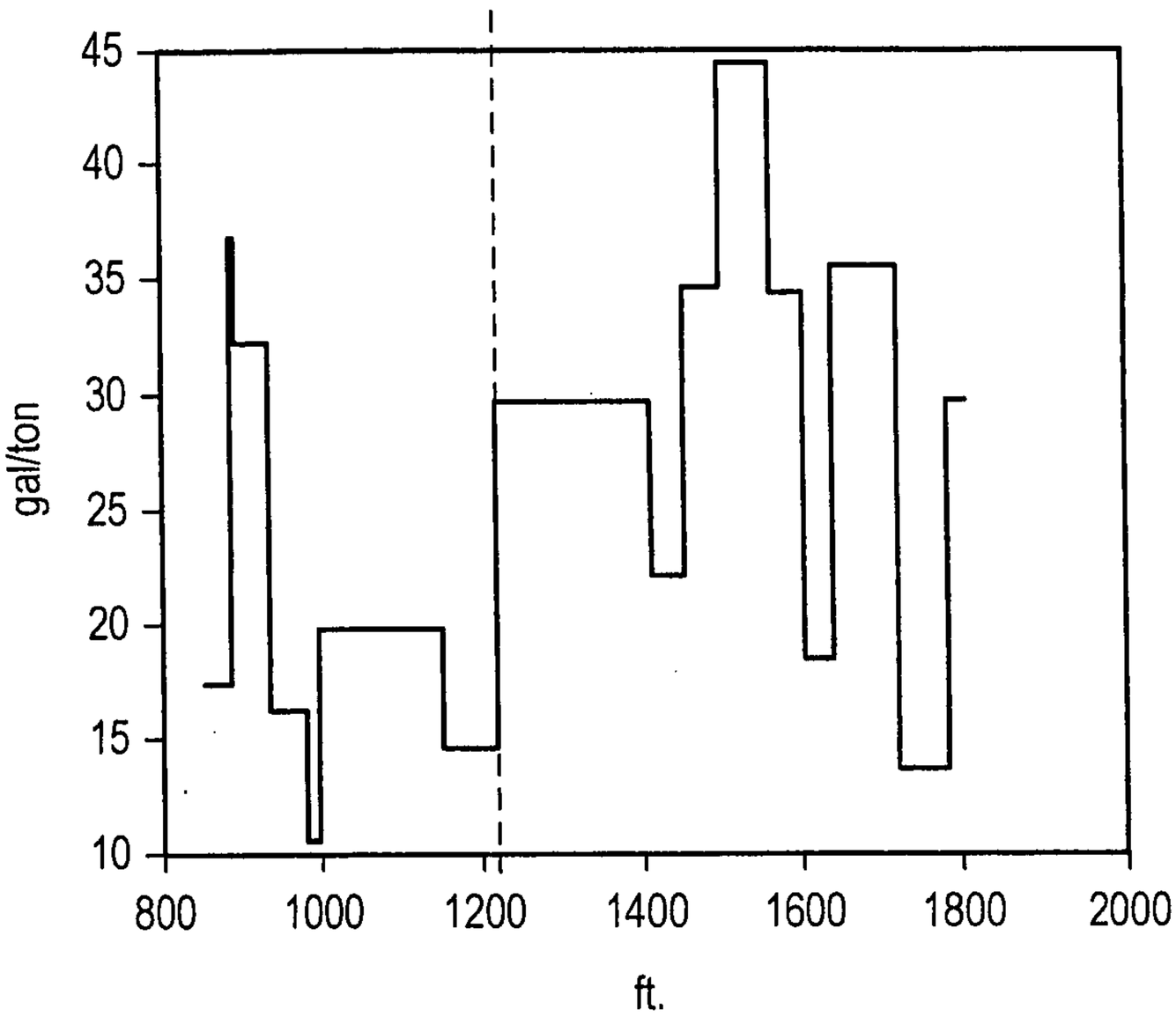


FIG. 258

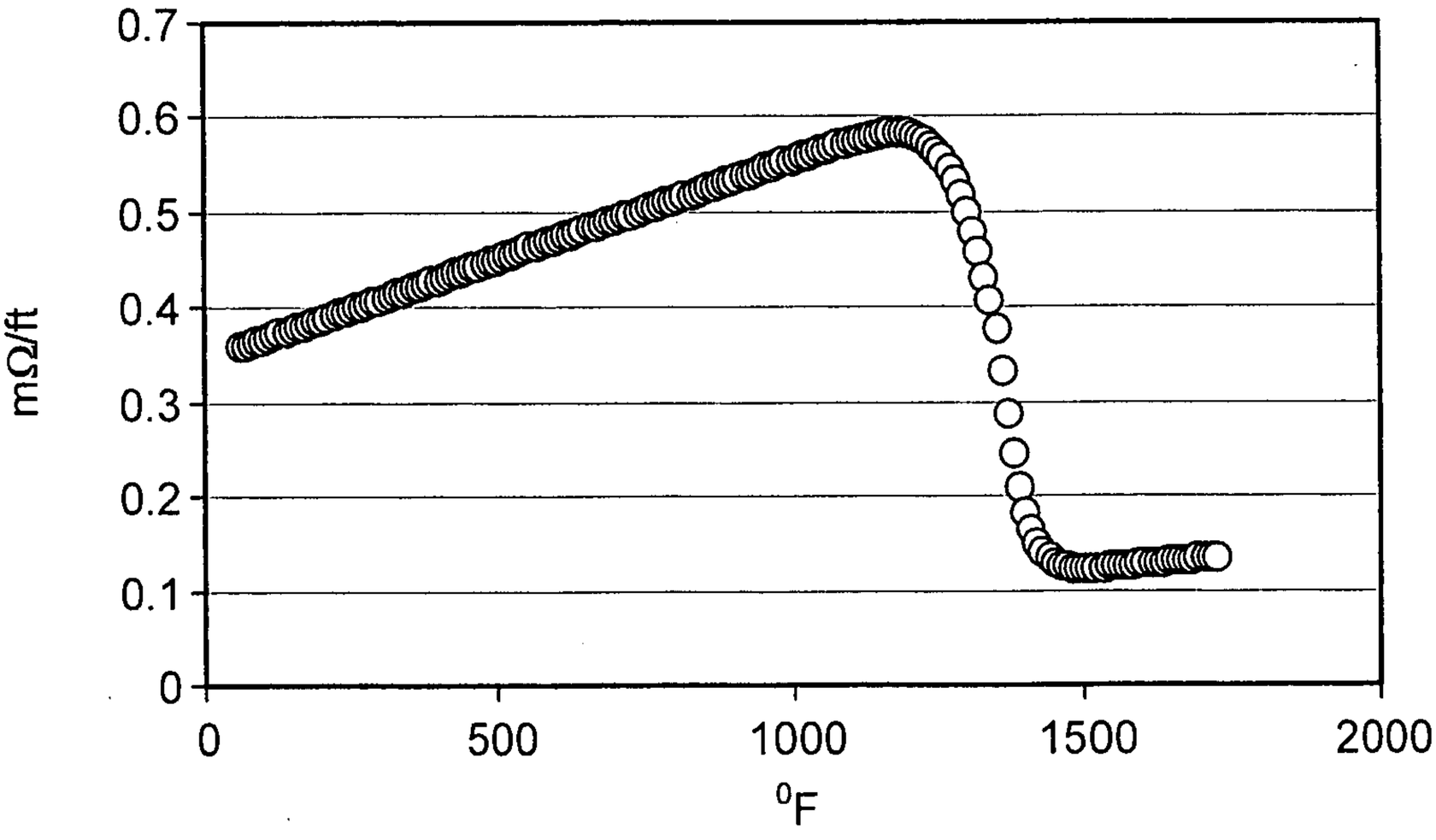


FIG. 259

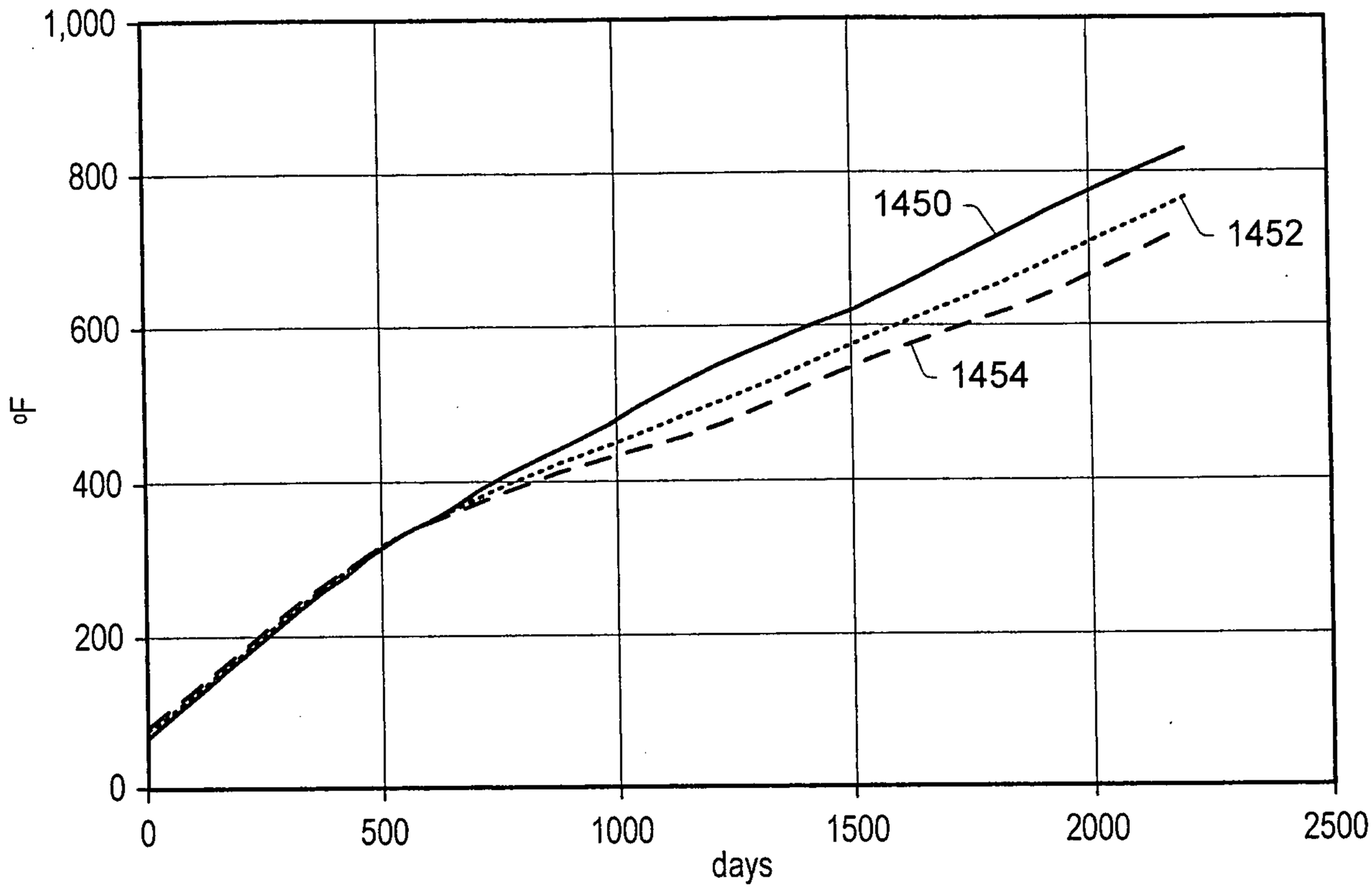


FIG. 260

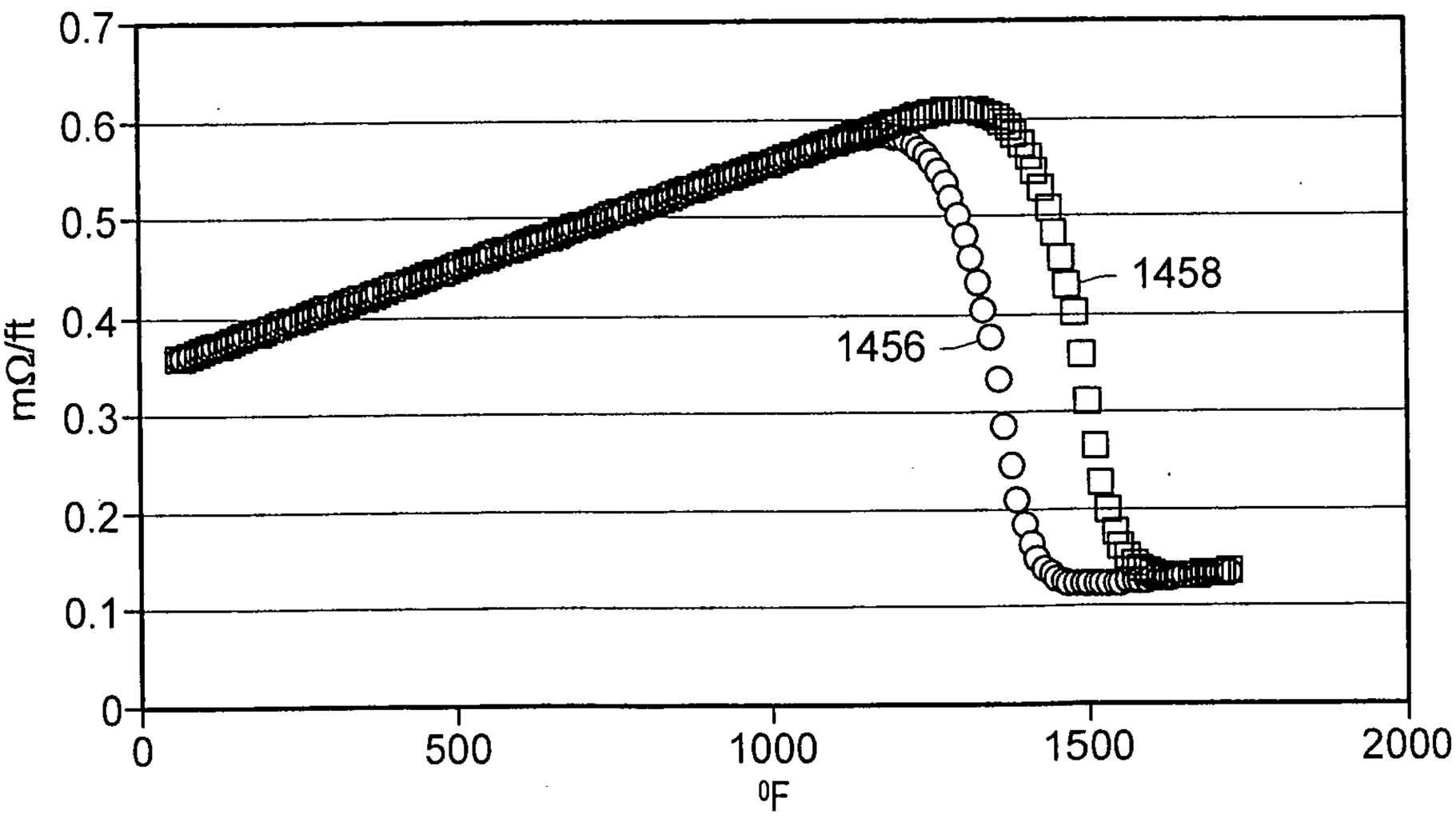


FIG. 261

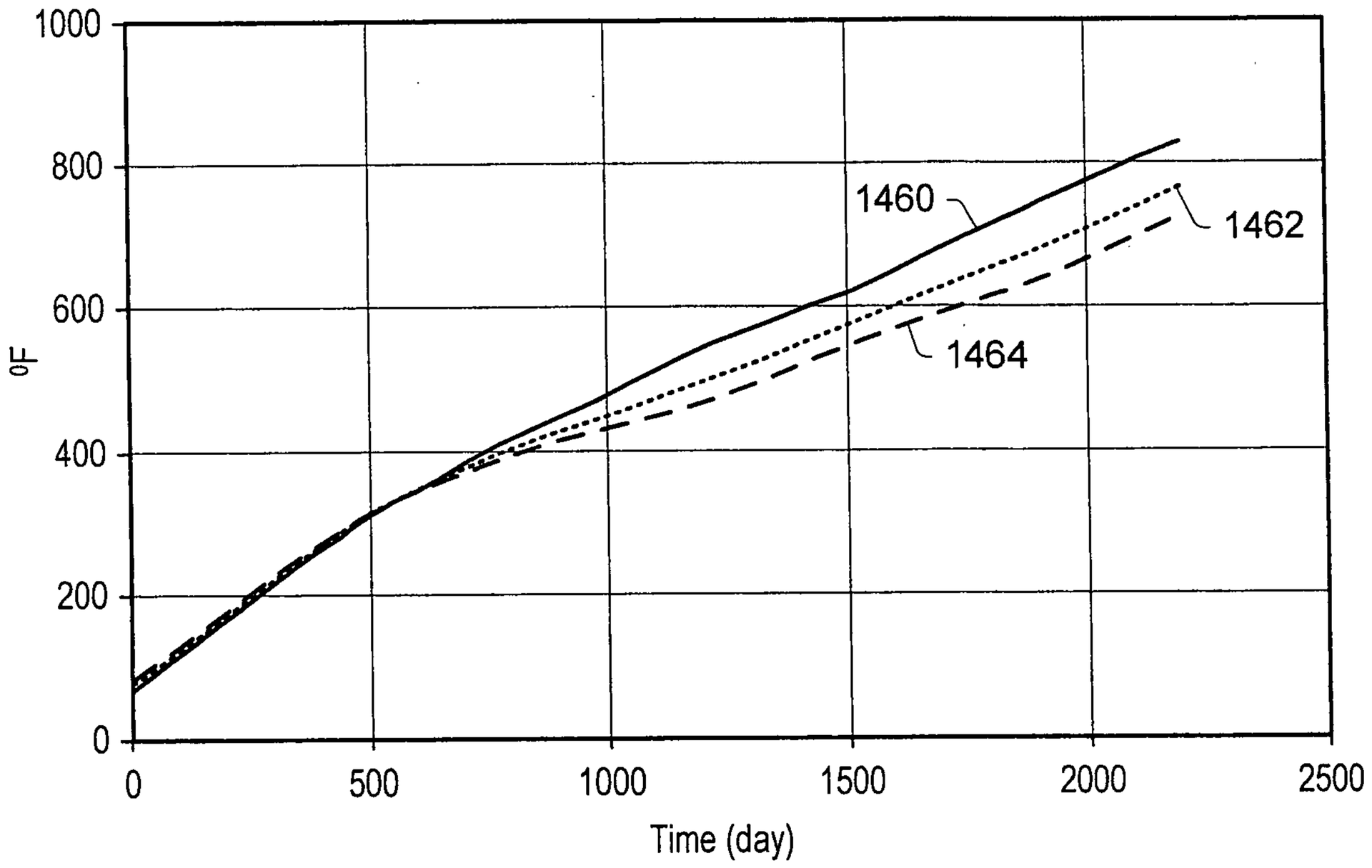


FIG. 262

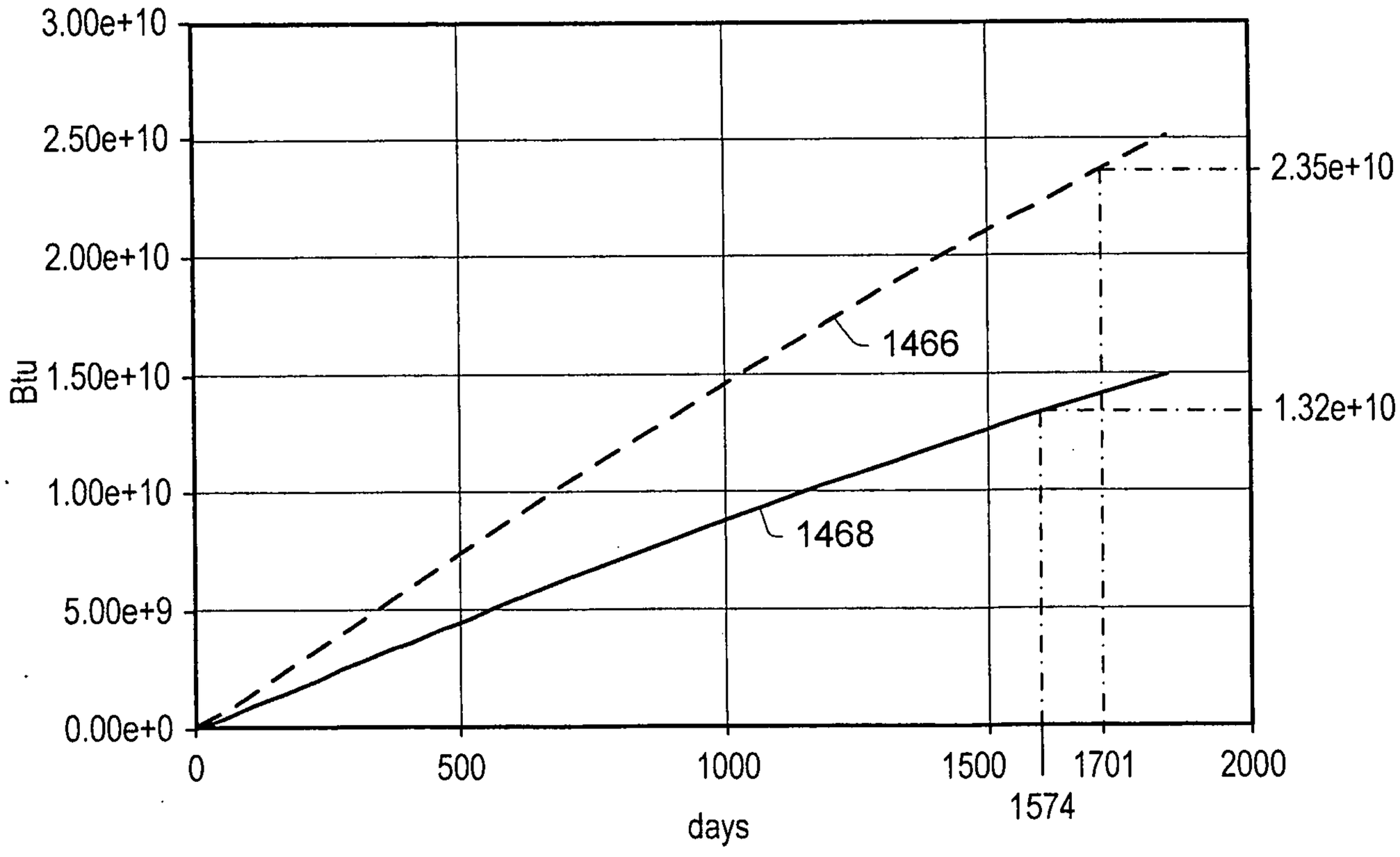


FIG. 263

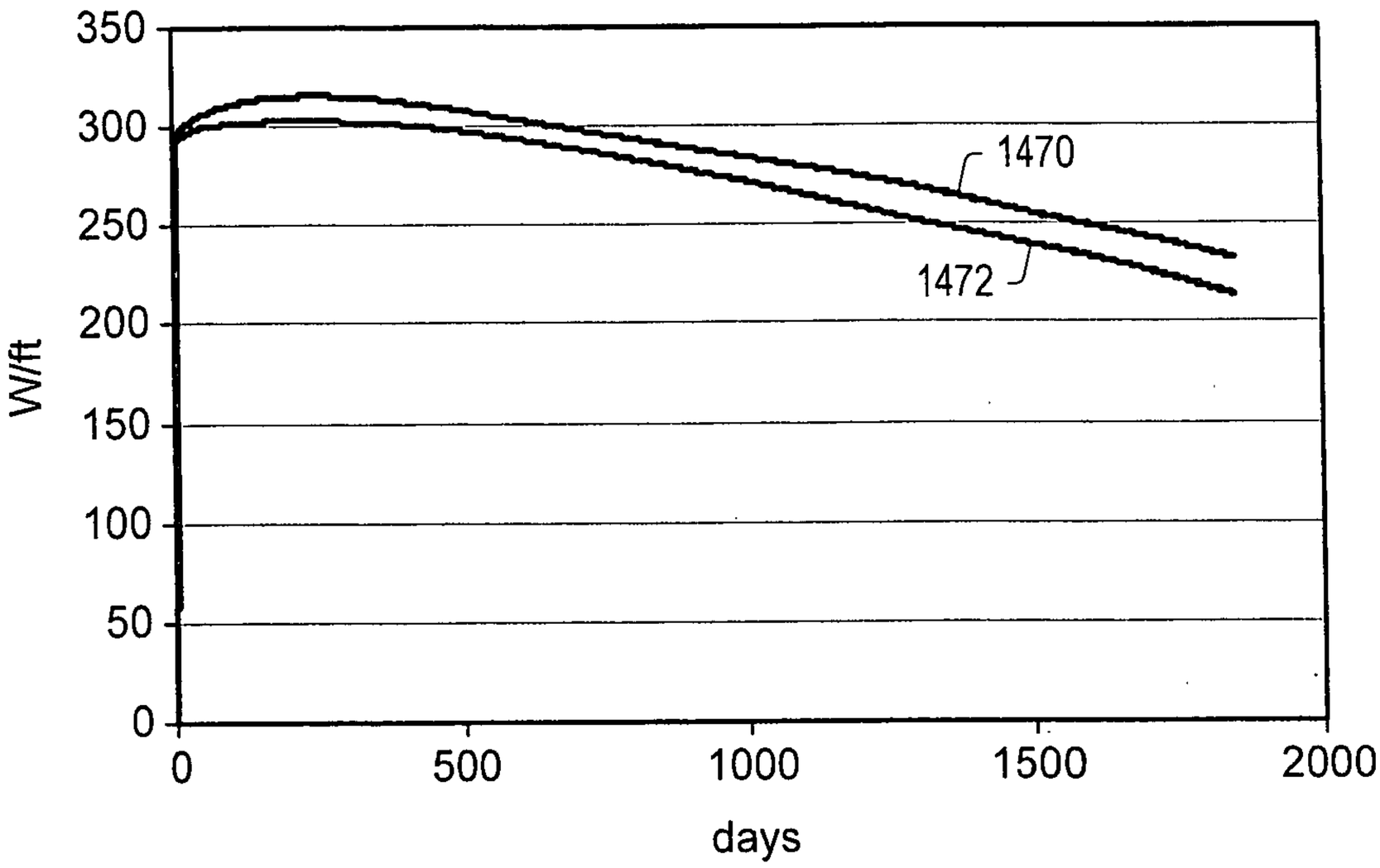


FIG. 264

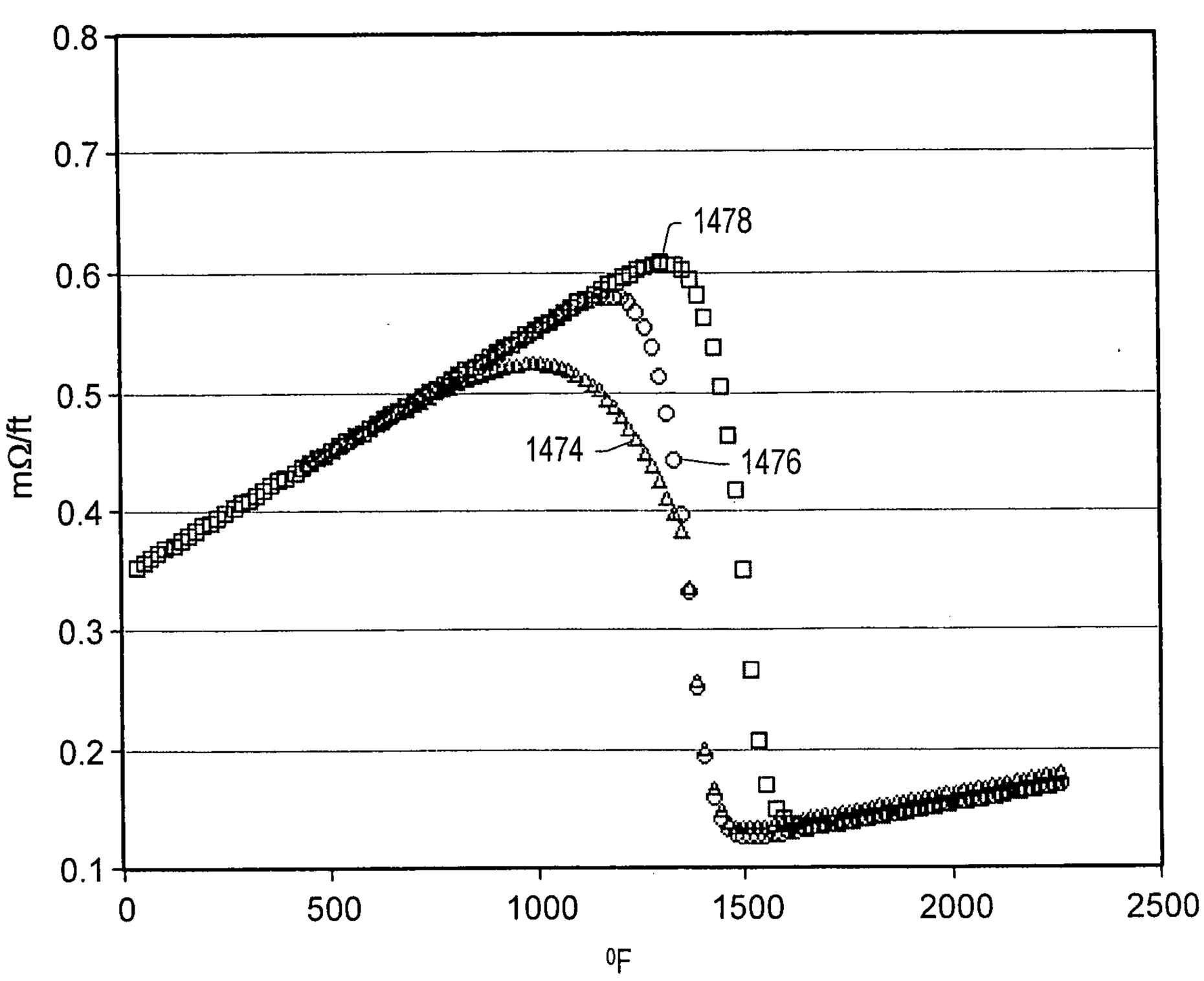


FIG. 265

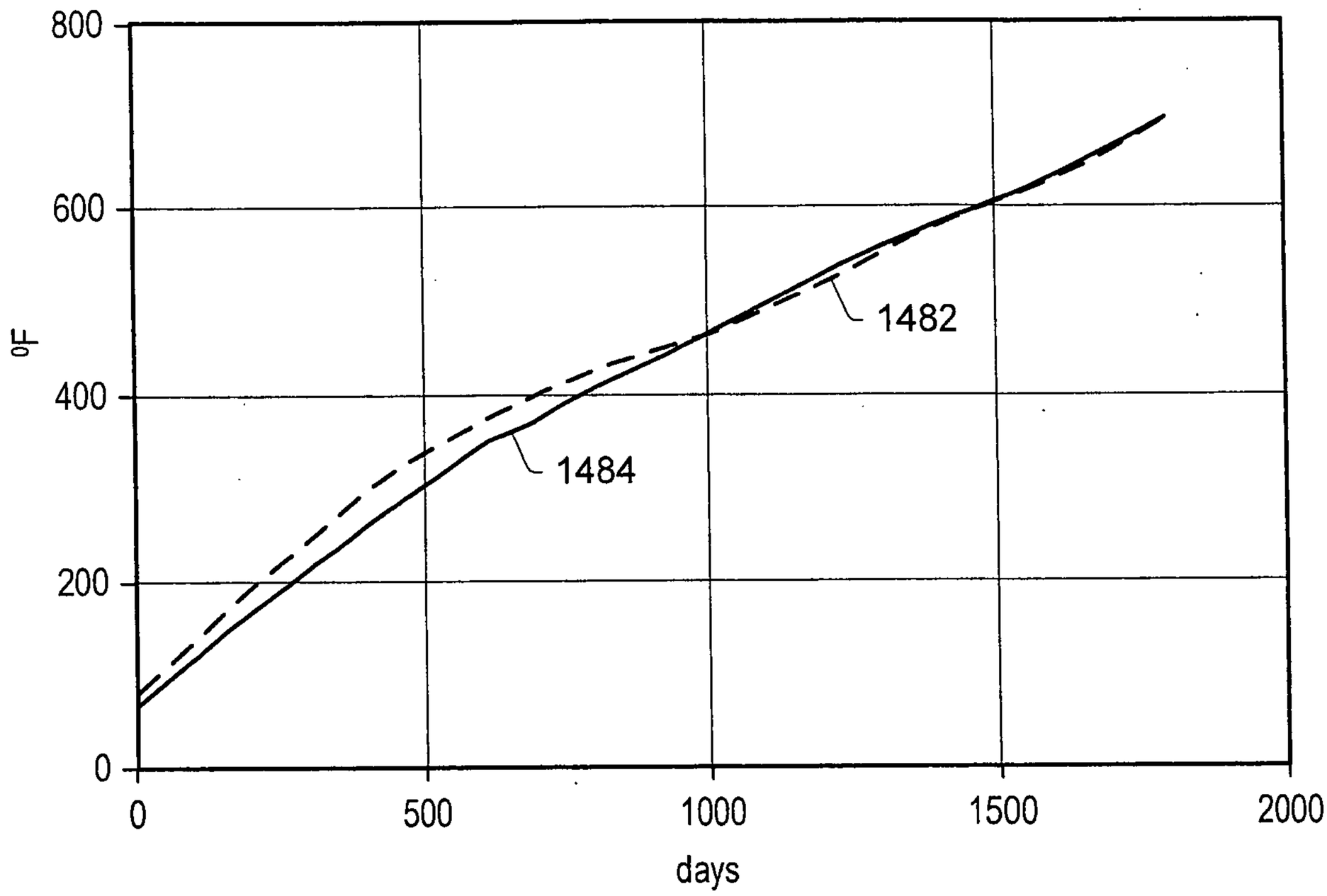


FIG. 266

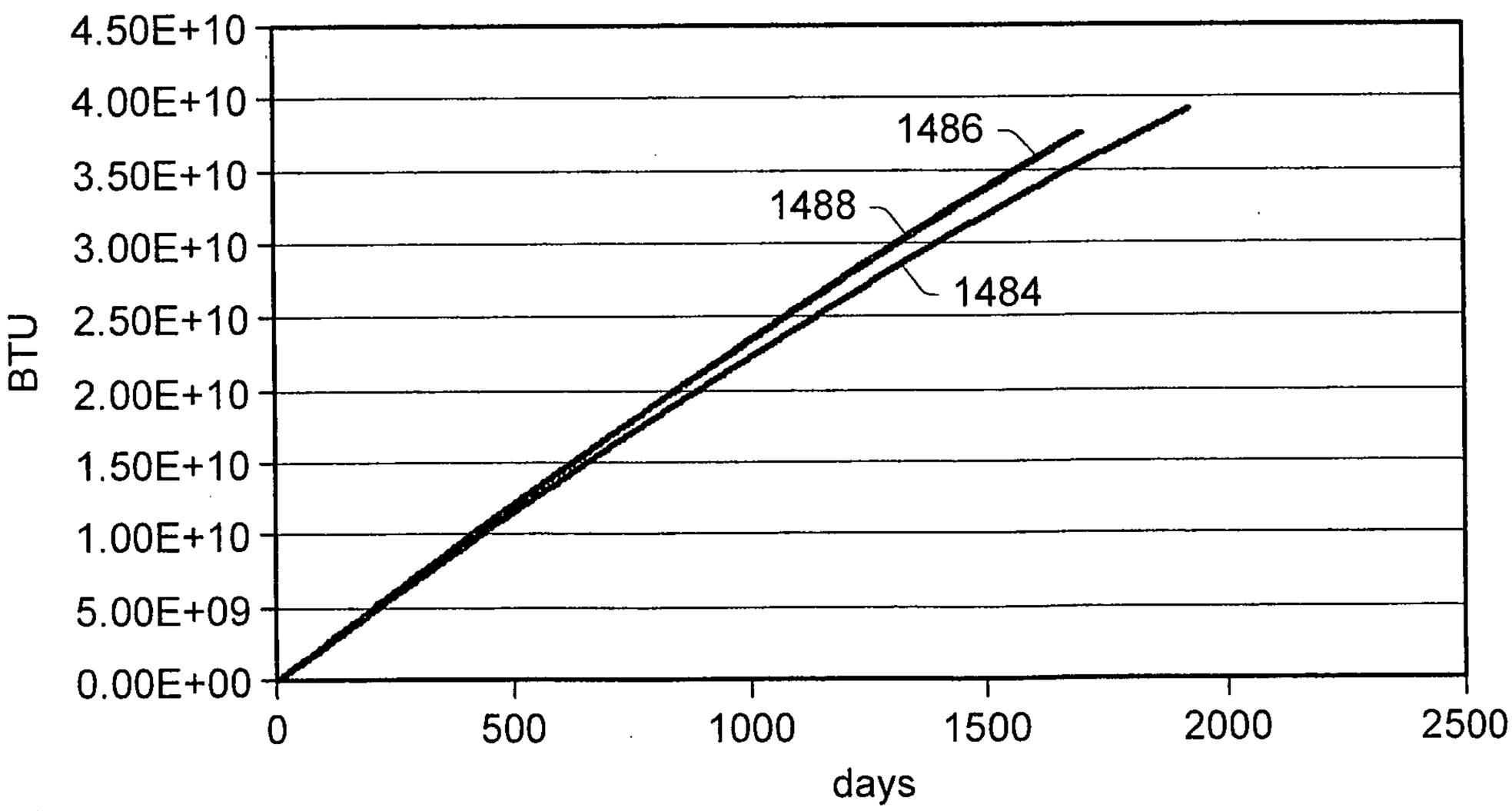


FIG. 267

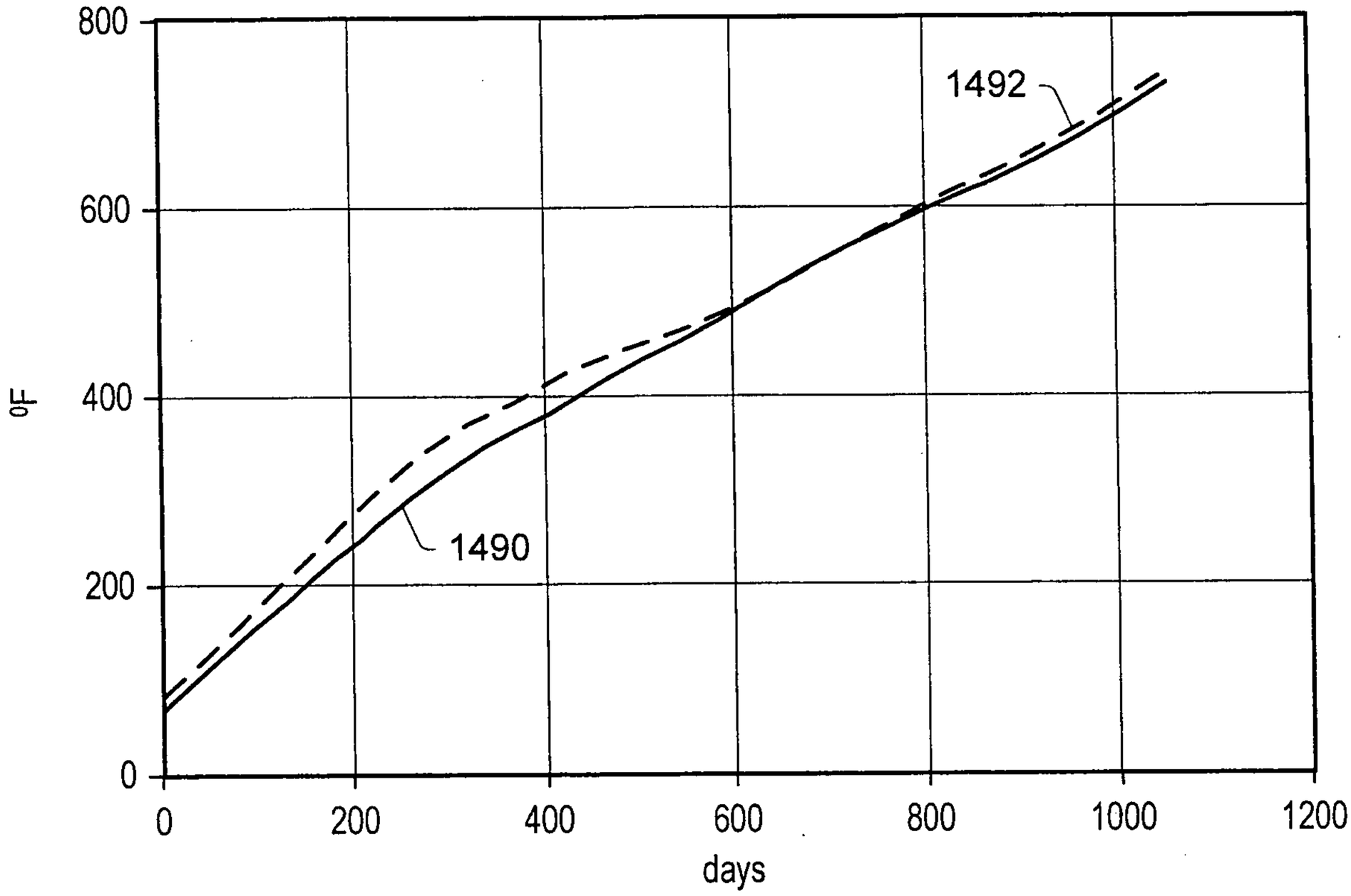


FIG. 268

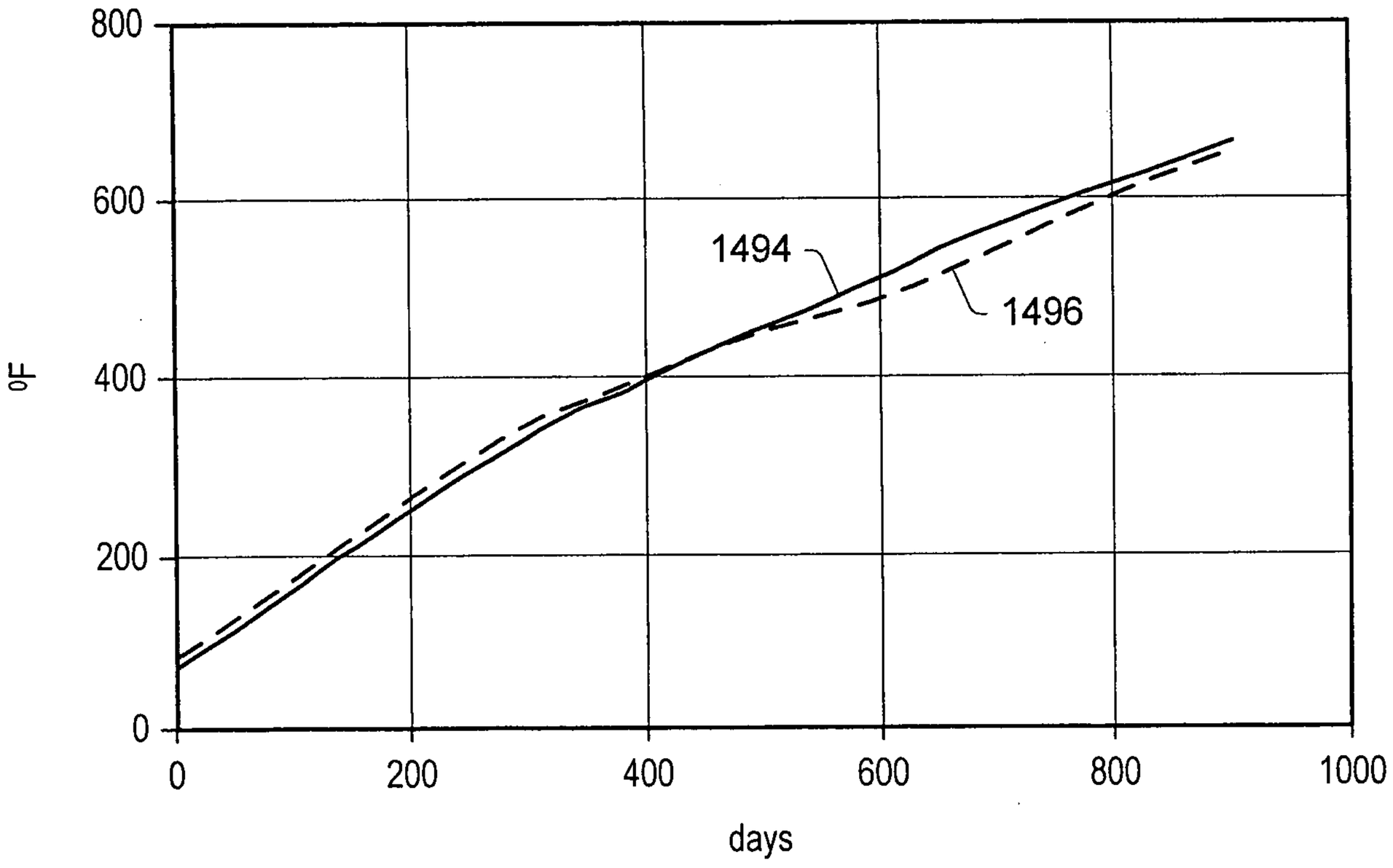


FIG. 269

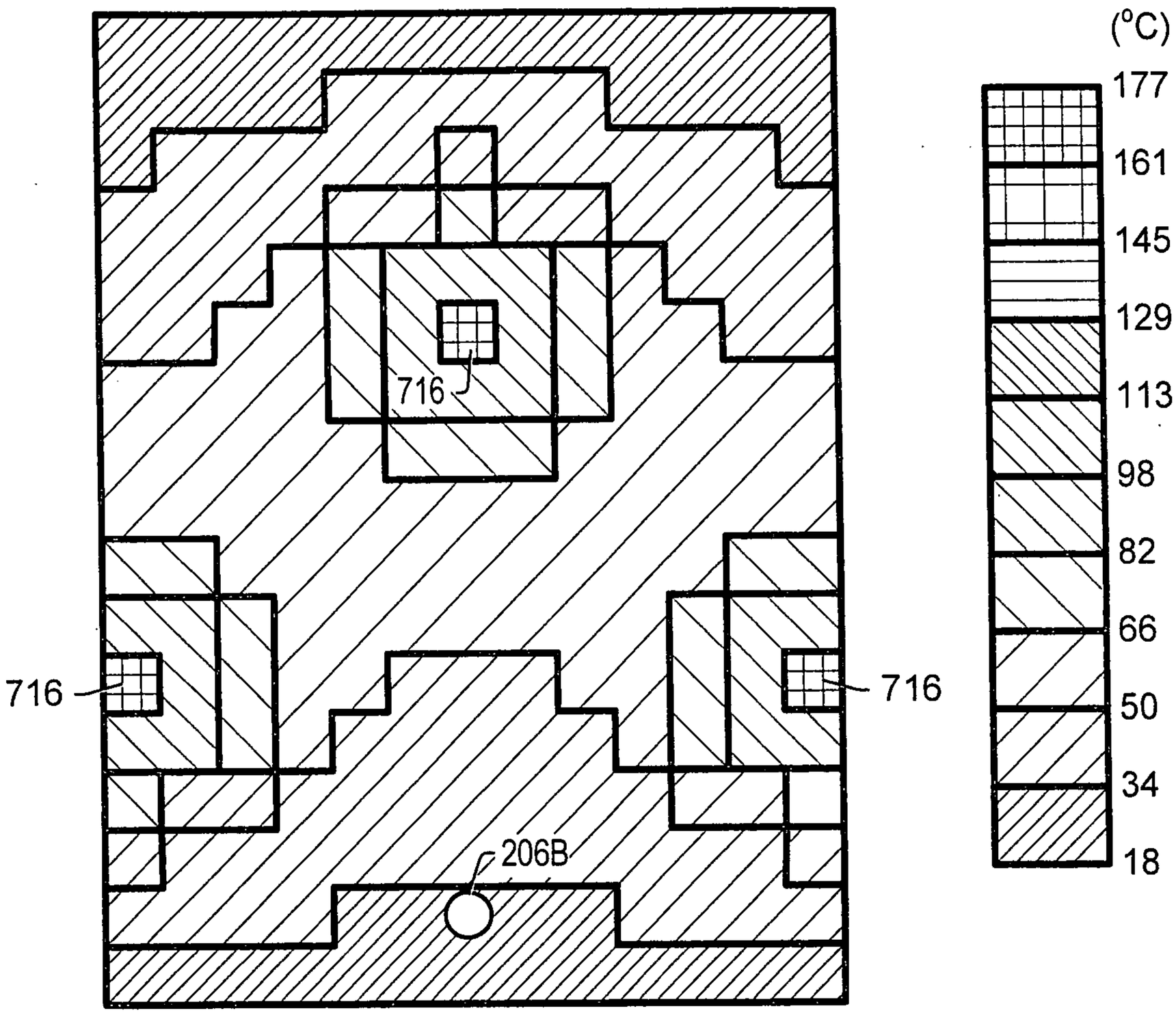


FIG. 270

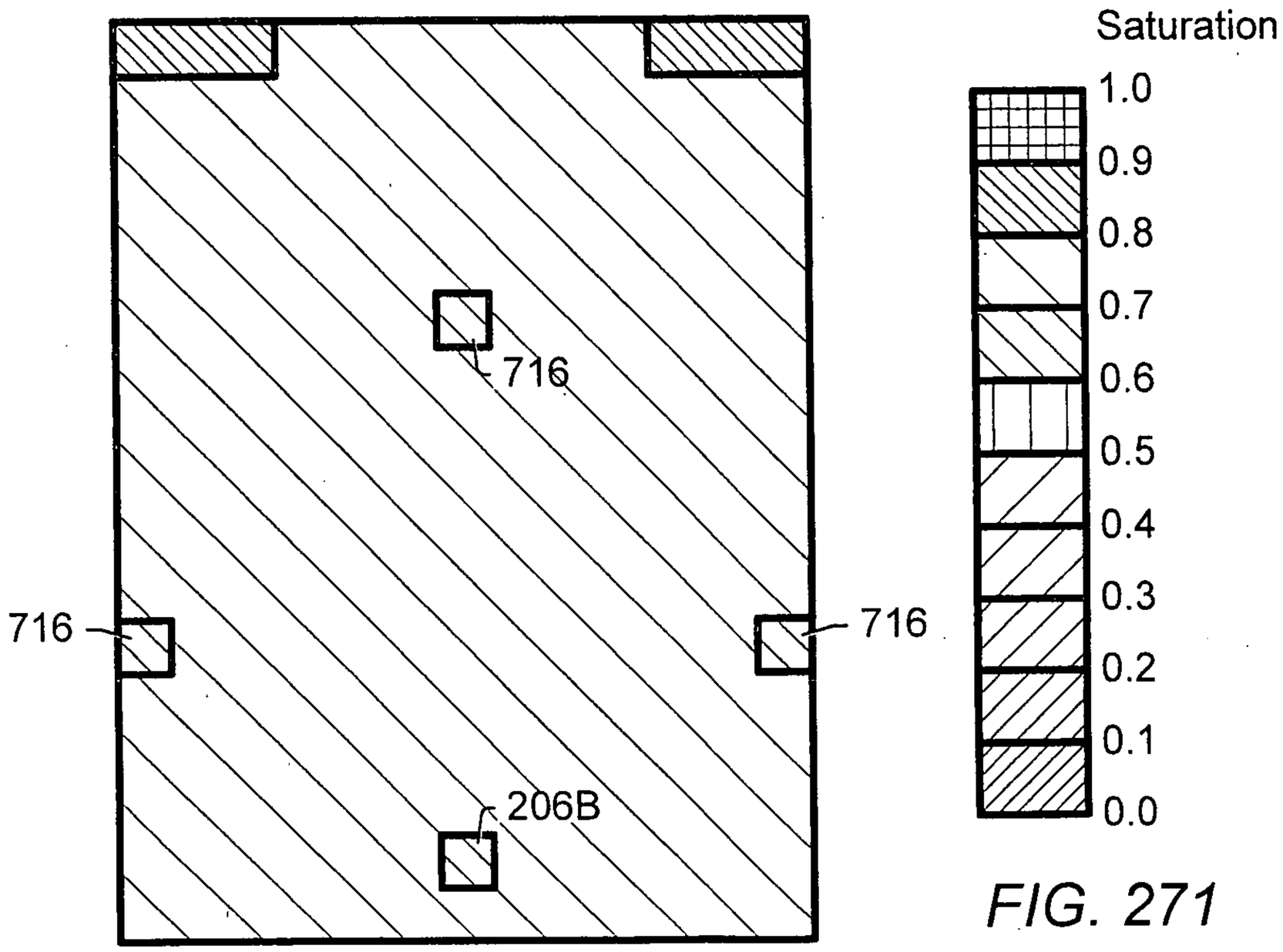


FIG. 271

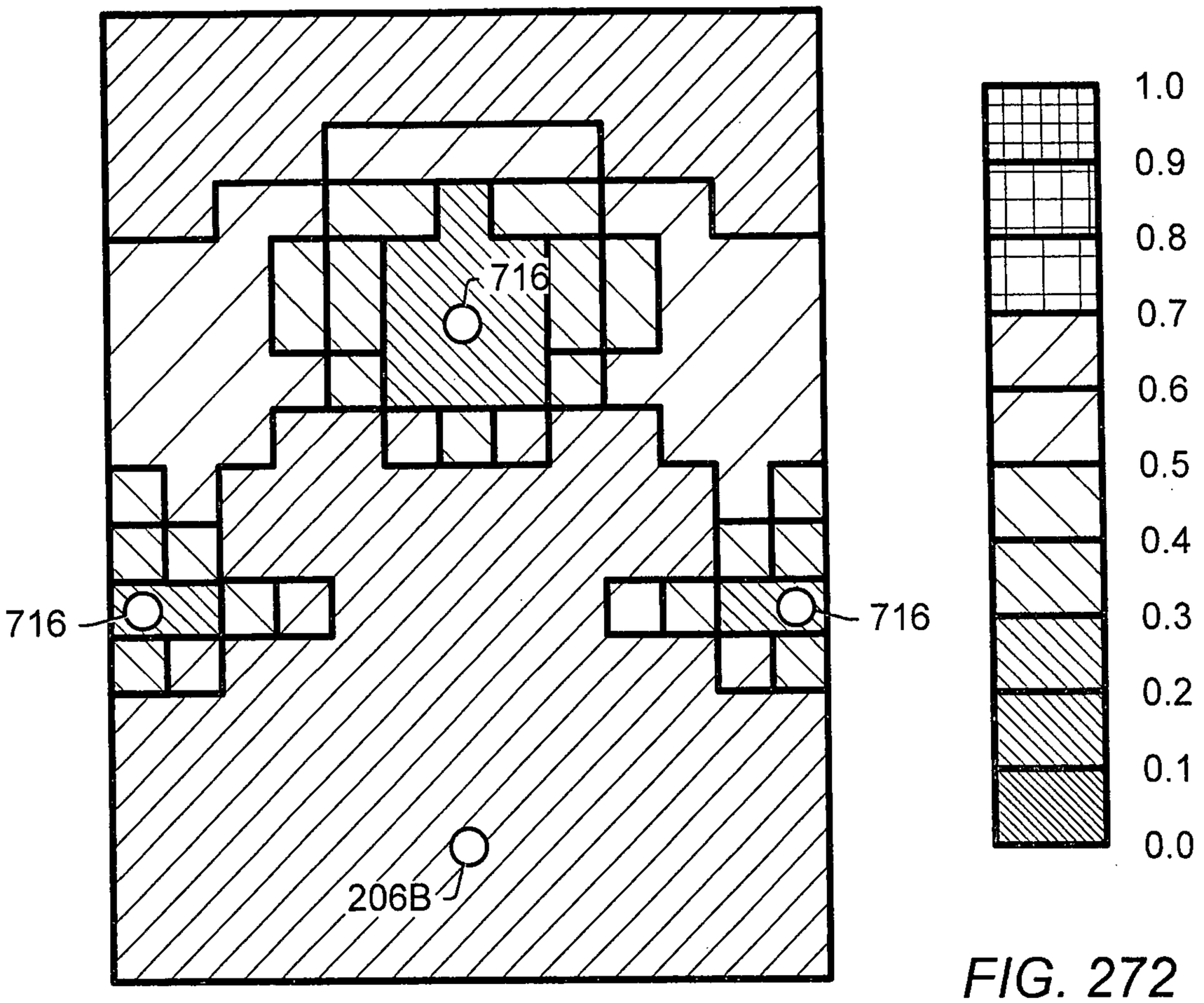


FIG. 272

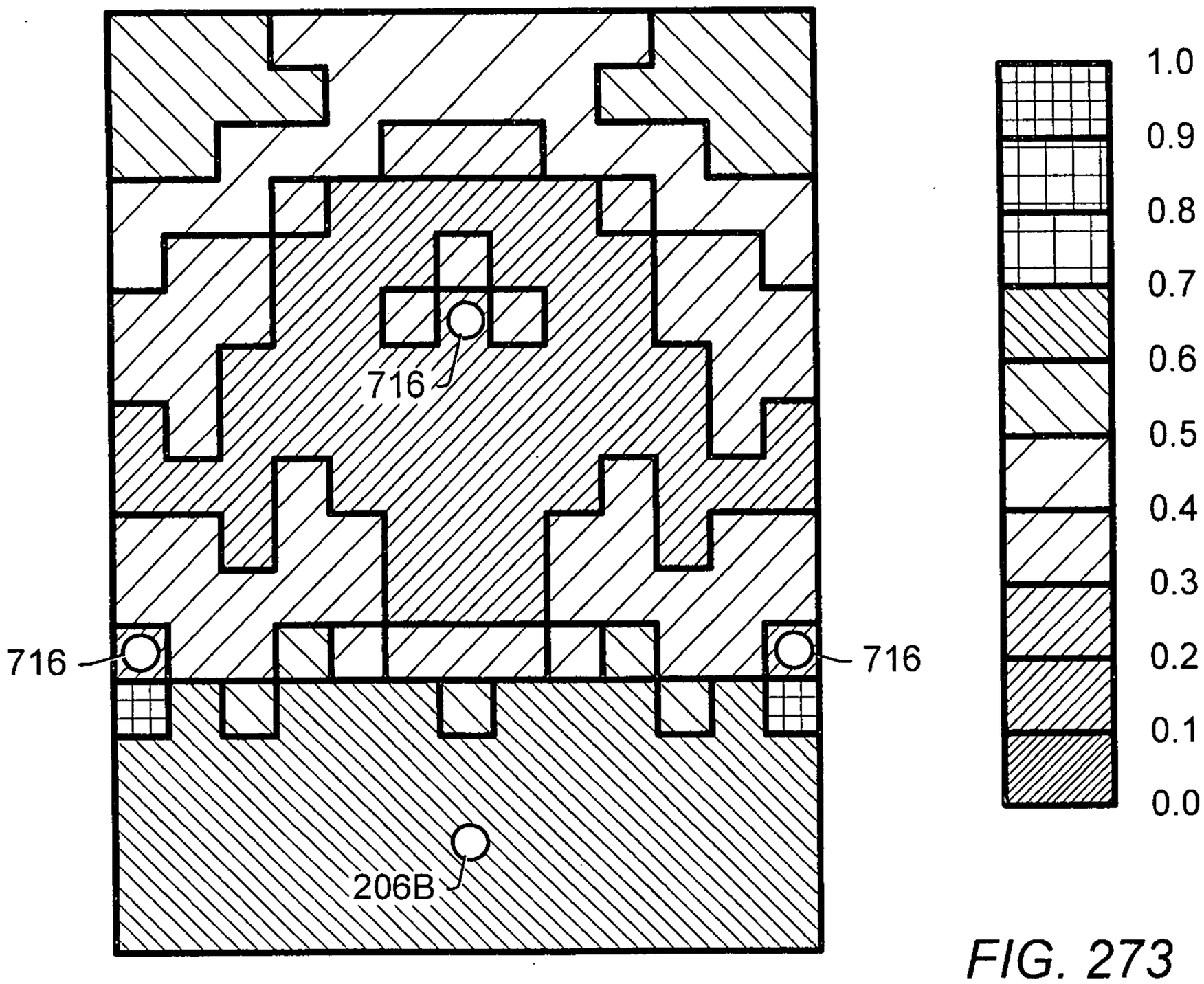


FIG. 273

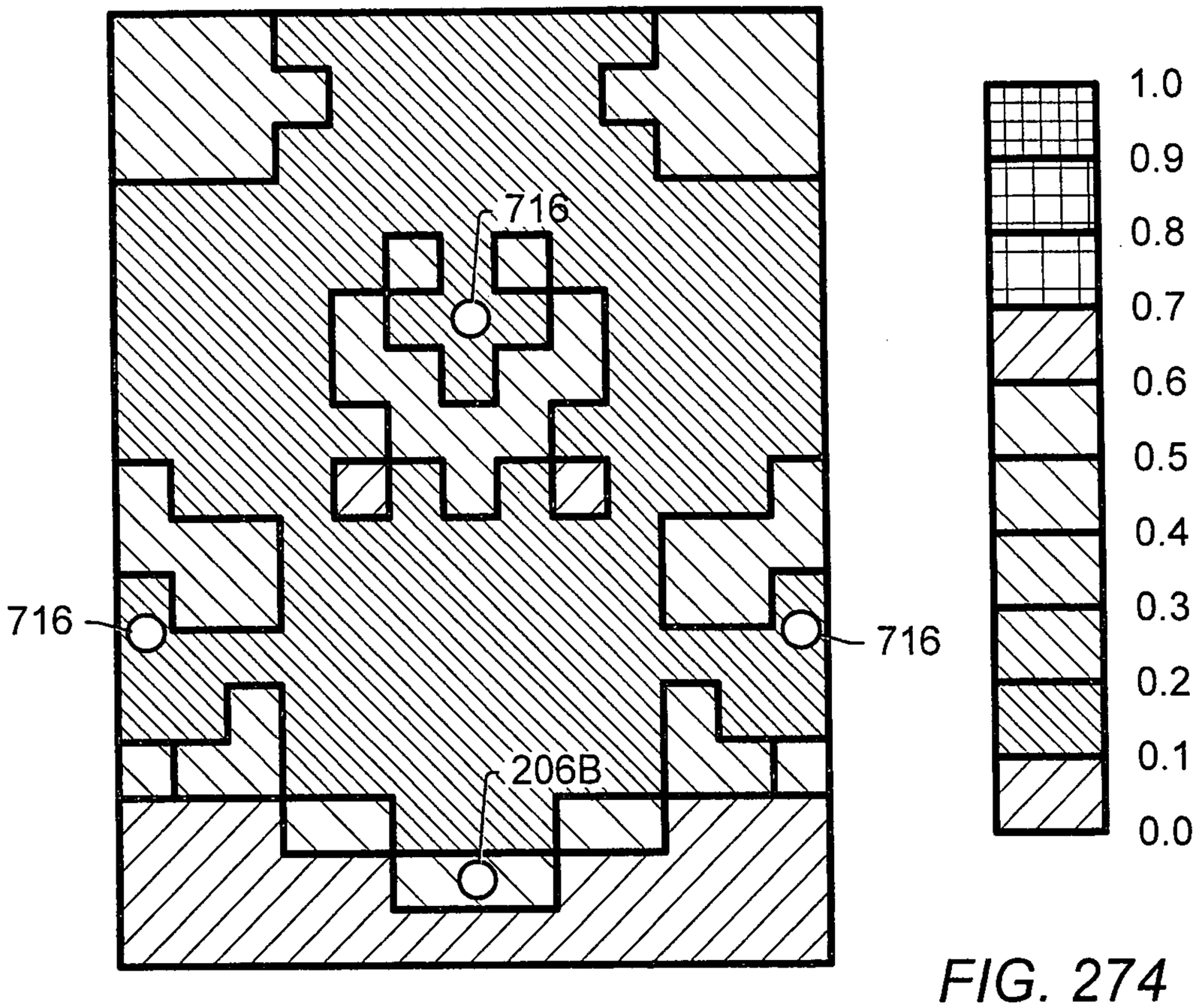


FIG. 274

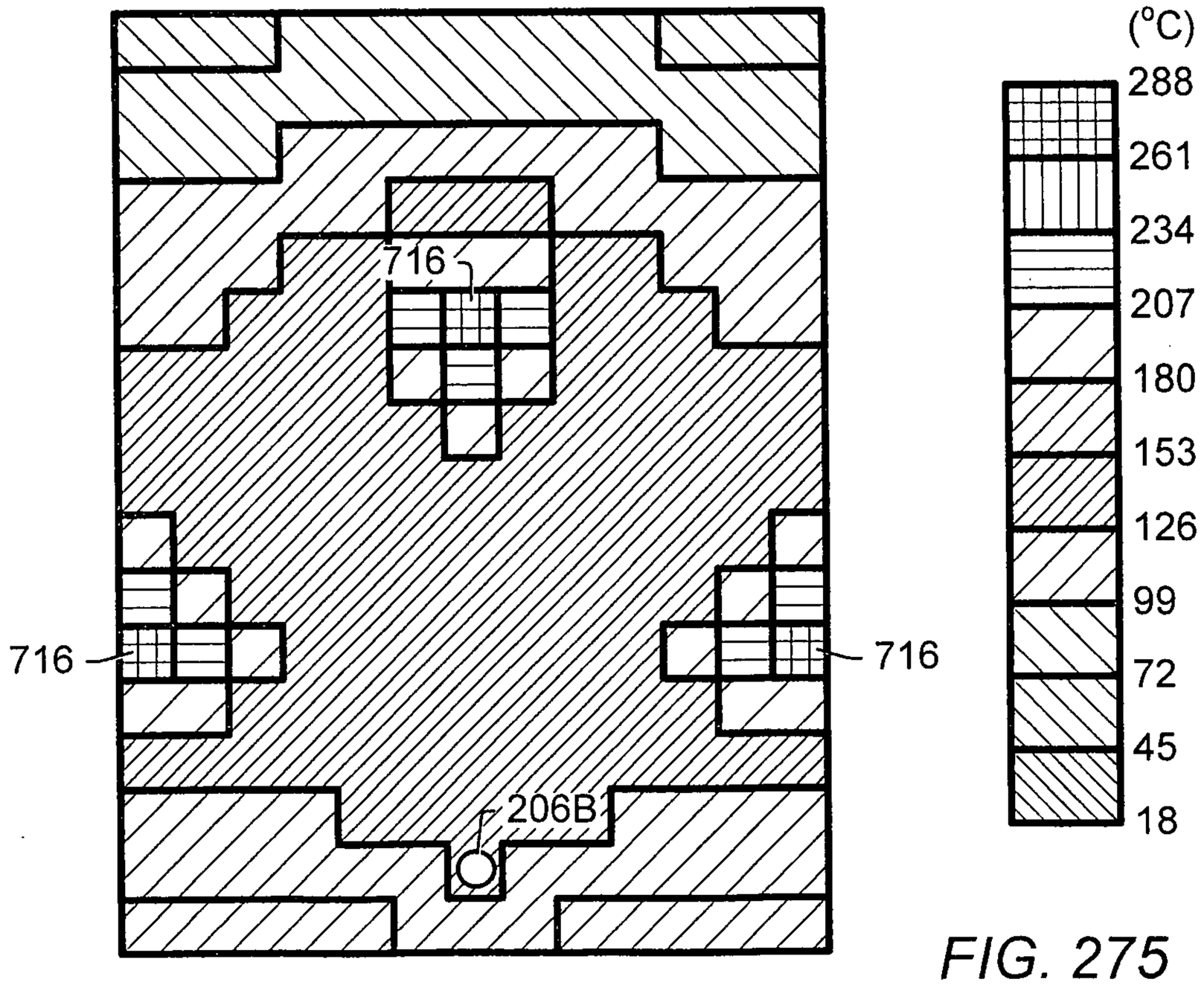


FIG. 275

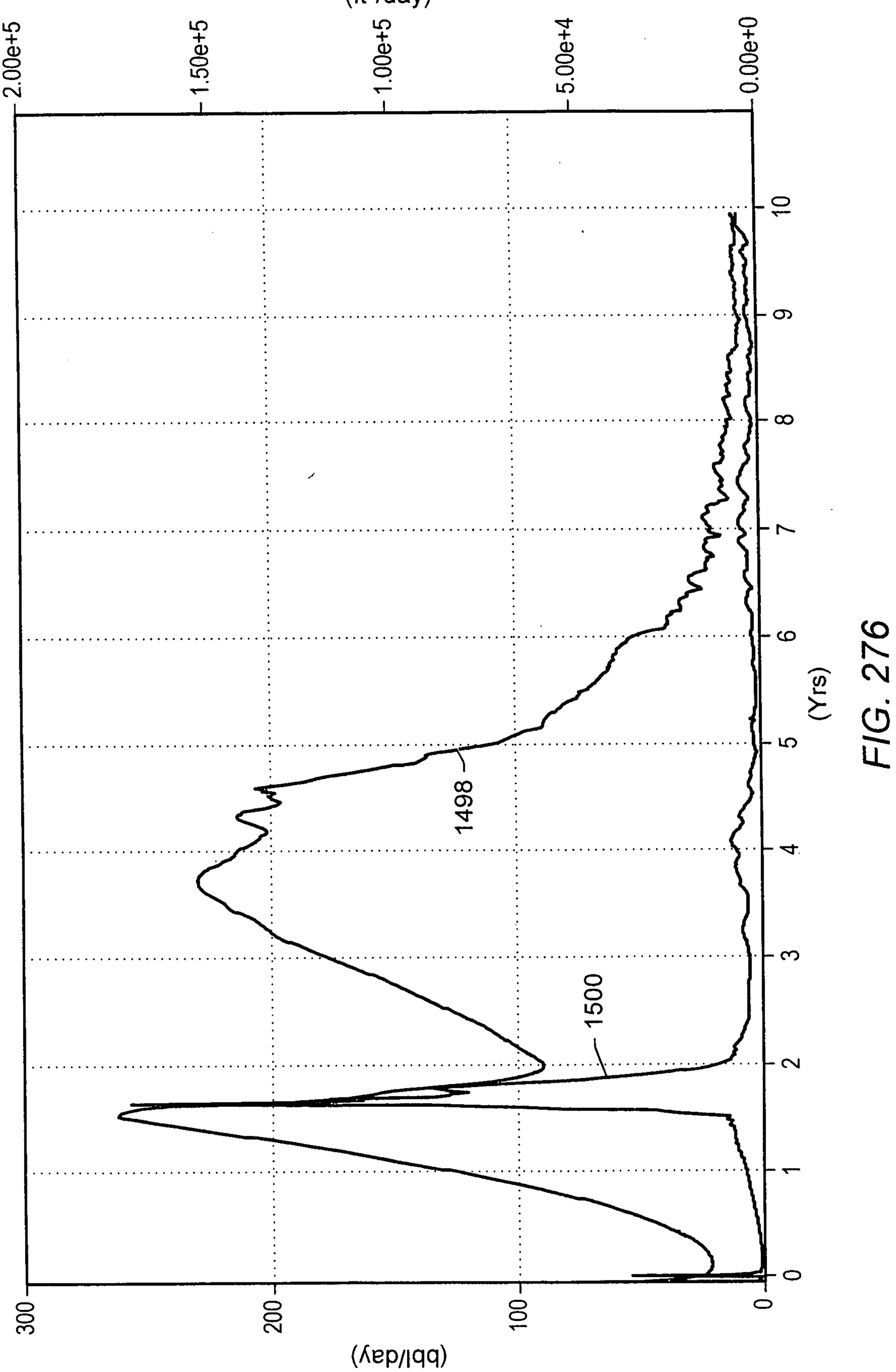

(ft3/day)
2.00e+5
1.50e+5
1.00e+5
5.00e+4
0.00e+0
10
9
8
7
6
5
4
3
2
1
0
(Yrs)
1498
1500
300
200
100
0
(bbl/day)

FIG. 276

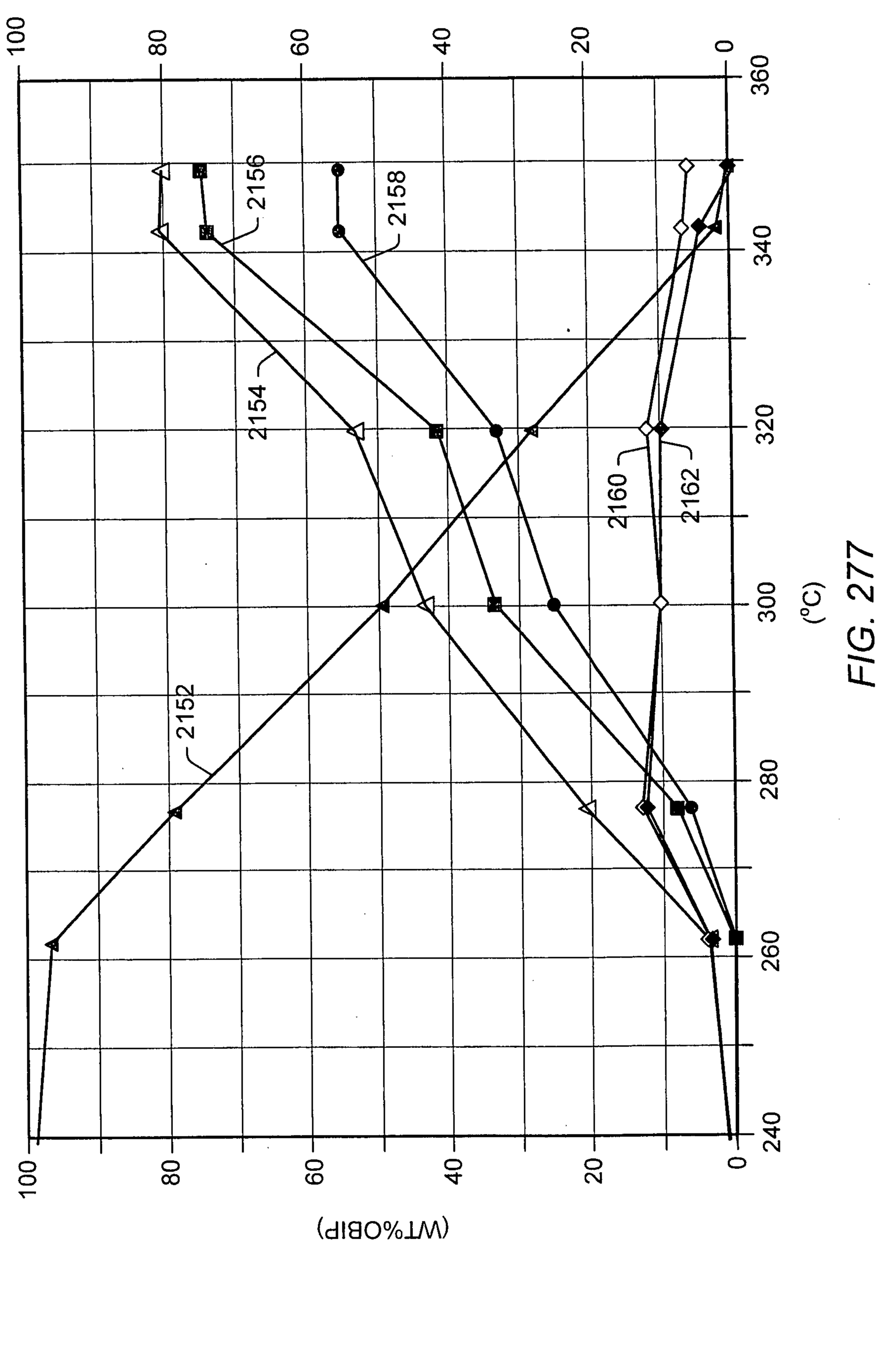

(vol%OBIP)
100
80
60
40
20
0
360
340
320
300
280
260
240
(°C)
2156
2158
2154
2160
2162
2152
100
80
60
40
20
0
(WT%OBIP)

FIG. 277

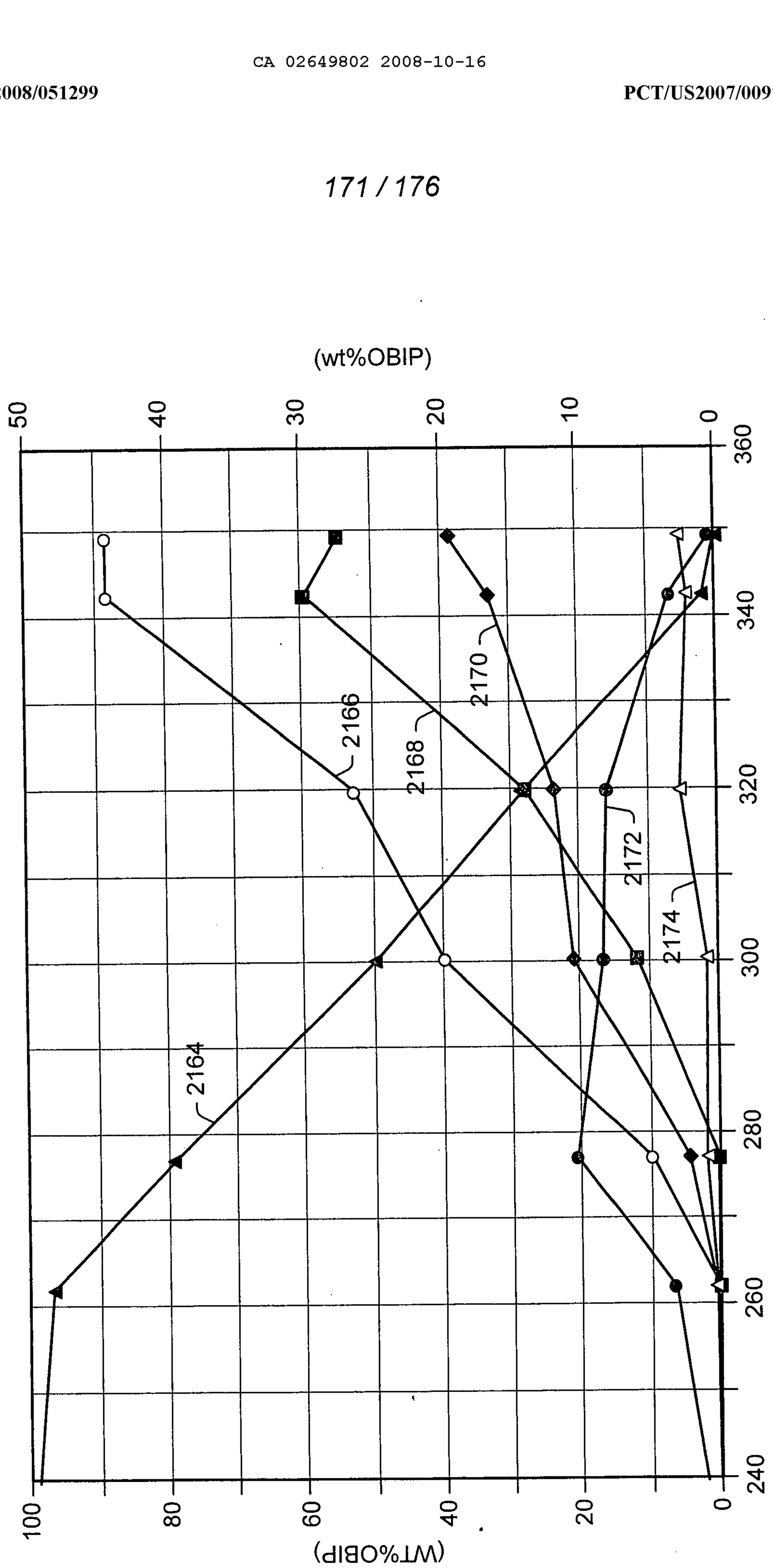

(wt%OBIP)
50
40
30
20
10
0
360
340
320
300
280
260
240
2166
2168
2170
2172
2174
2164
(°C)
100
80
60
40
20
0
(WT%OBIP)

FIG. 278

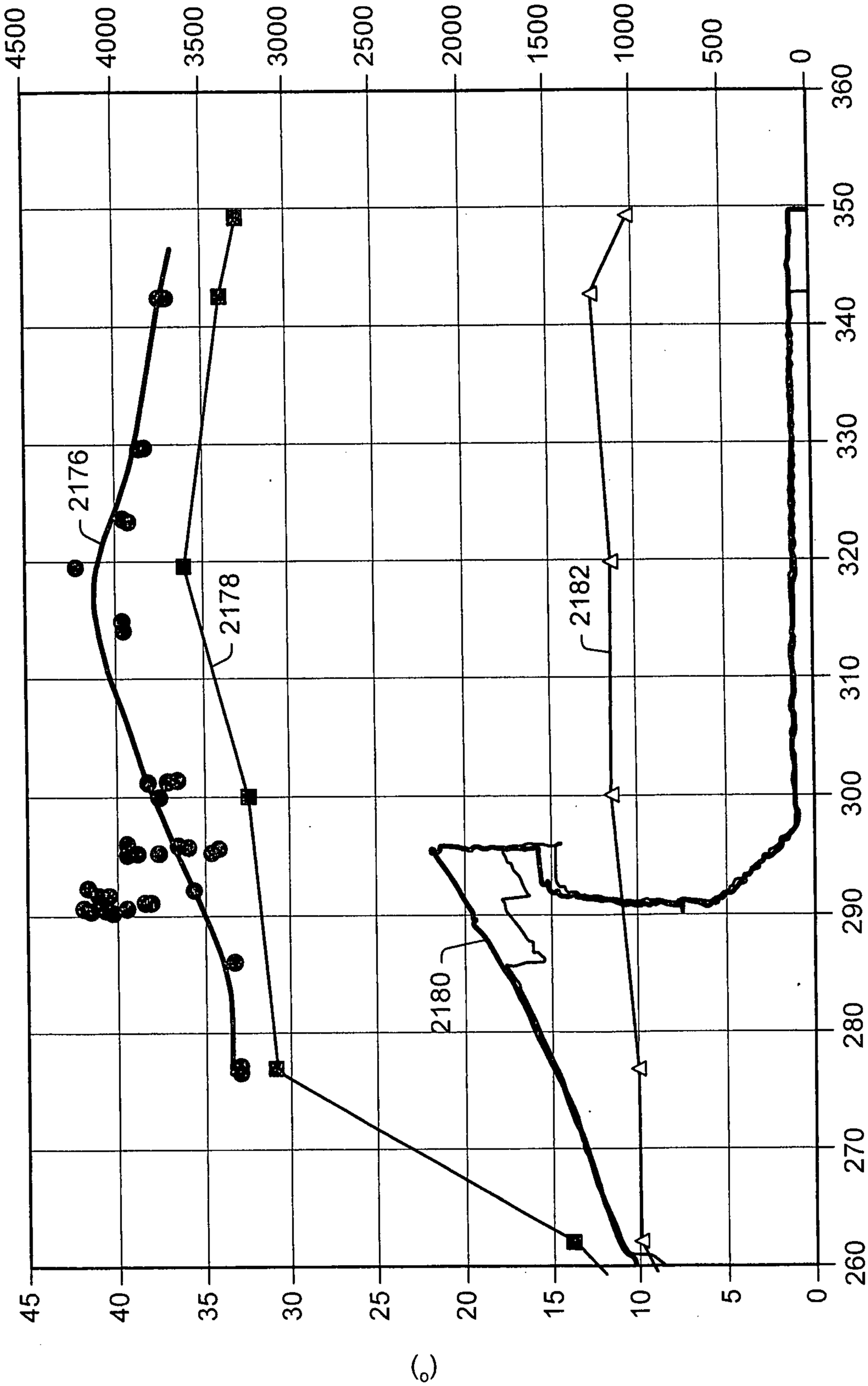

(psig)
4500
4000
3500
3000
2500
2000
1500
1000
500
0
360
350
340
330
320
310
300
290
280
270
260
(°C)
2176
2178
2180
2182
45
40
35
30
25
20
15
10
5
0
(°)

FIG. 279

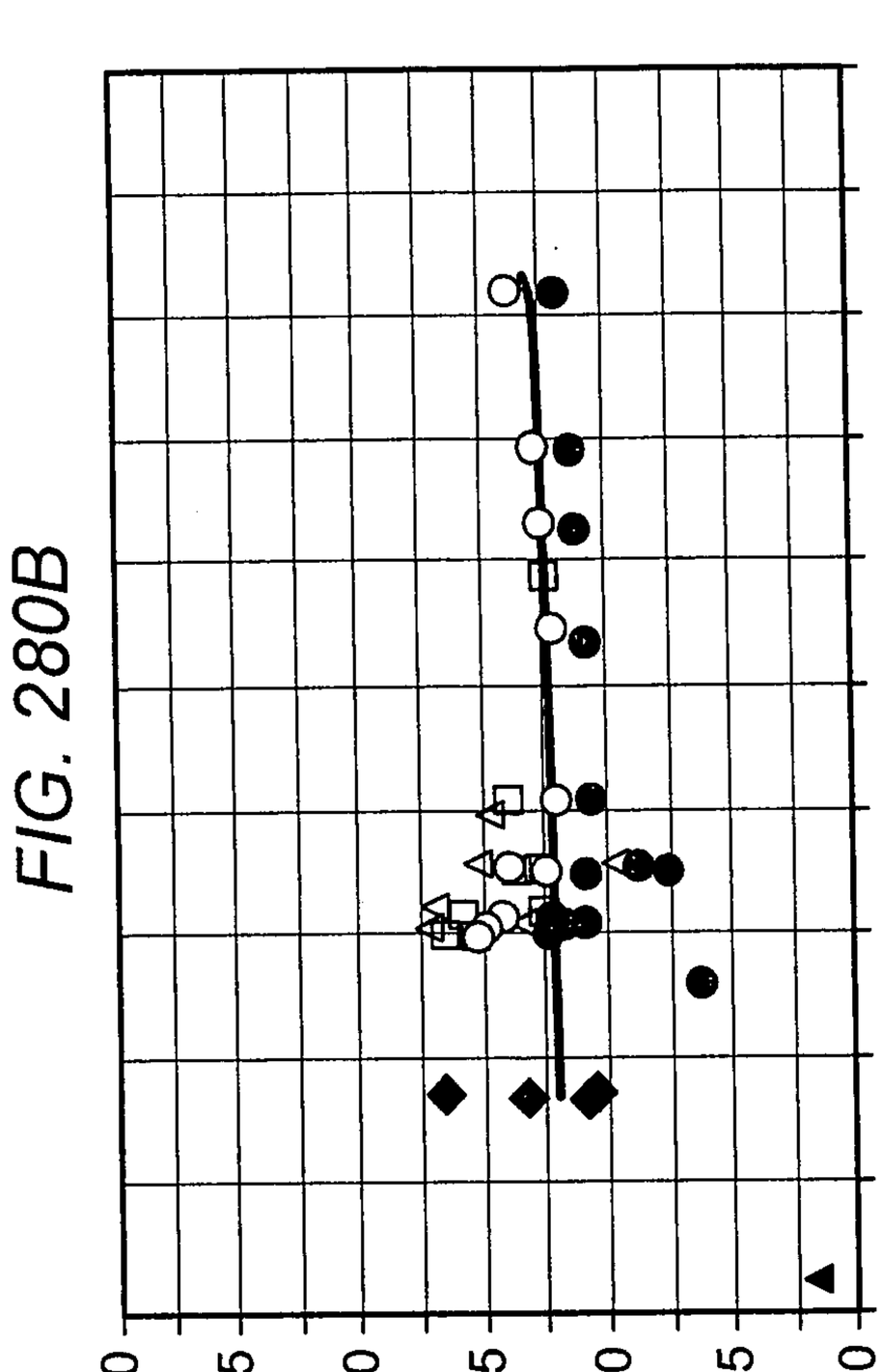


FIG. 280A

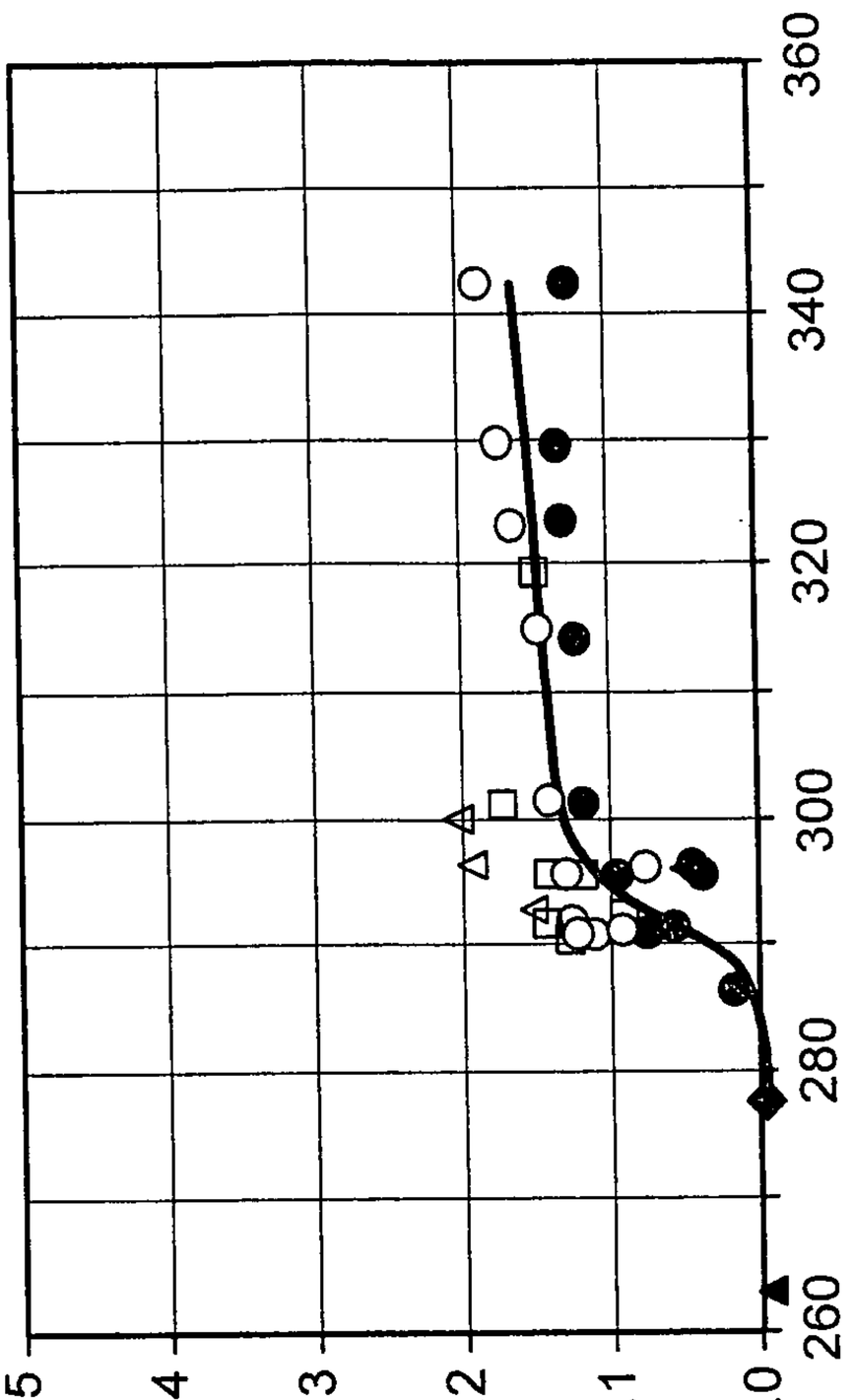


FIG. 280B

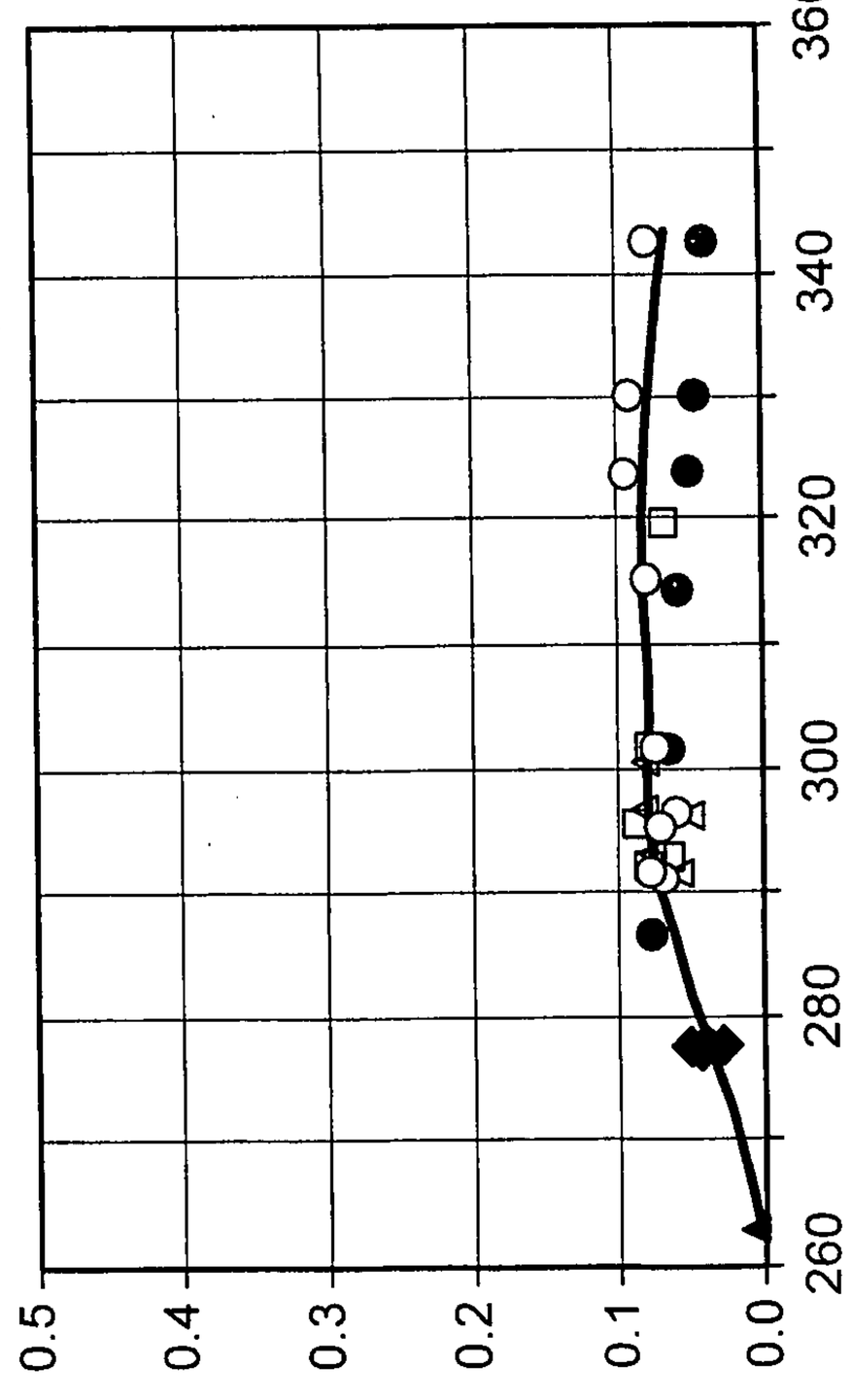


FIG. 280C

FIG. 280D

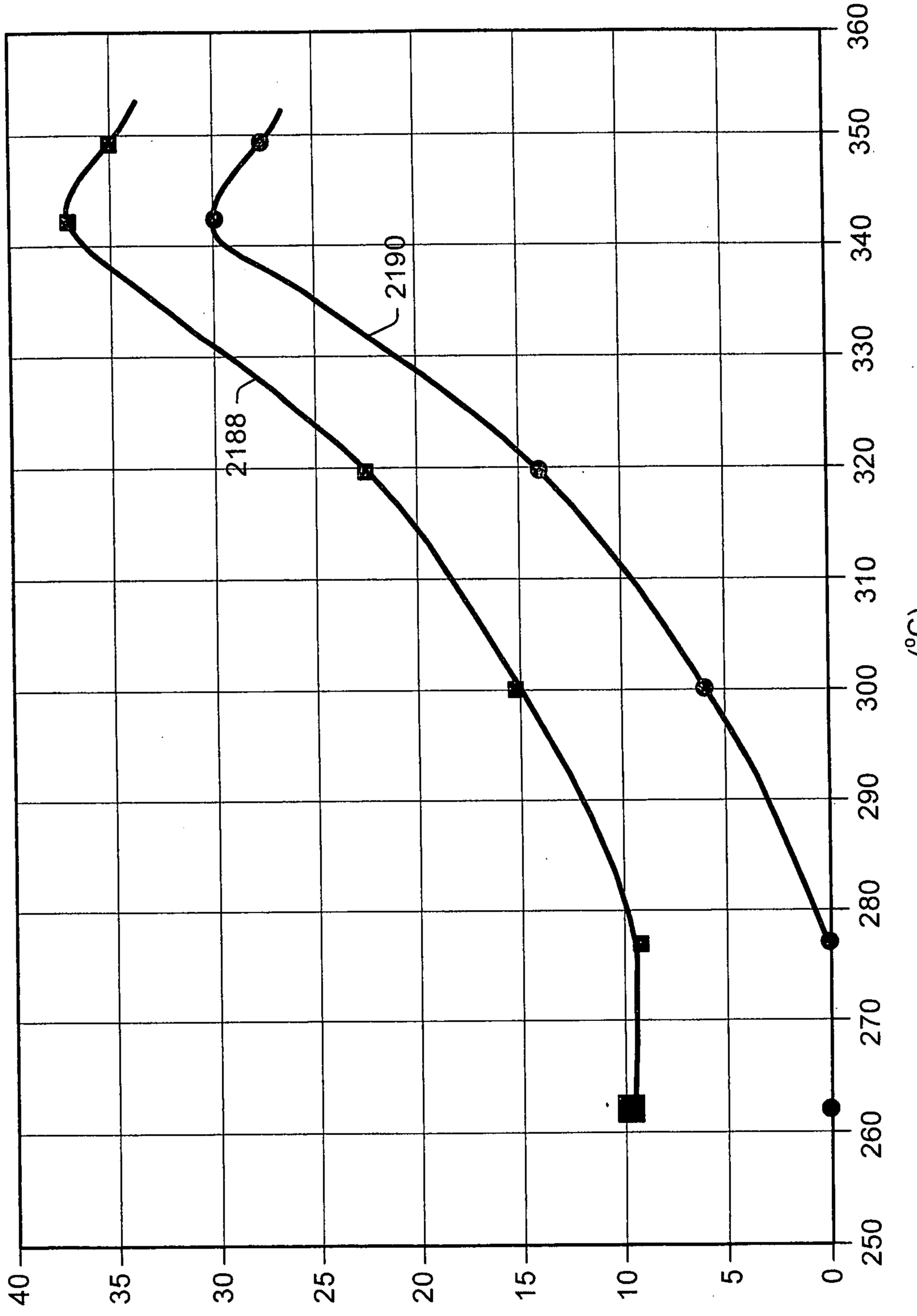

2190
2188
360
350
340
330
320
310
300
290
280
270
260
250
(°C)
40
35
30
25
20
15
10
5
0
Coke Yield

FIG. 281

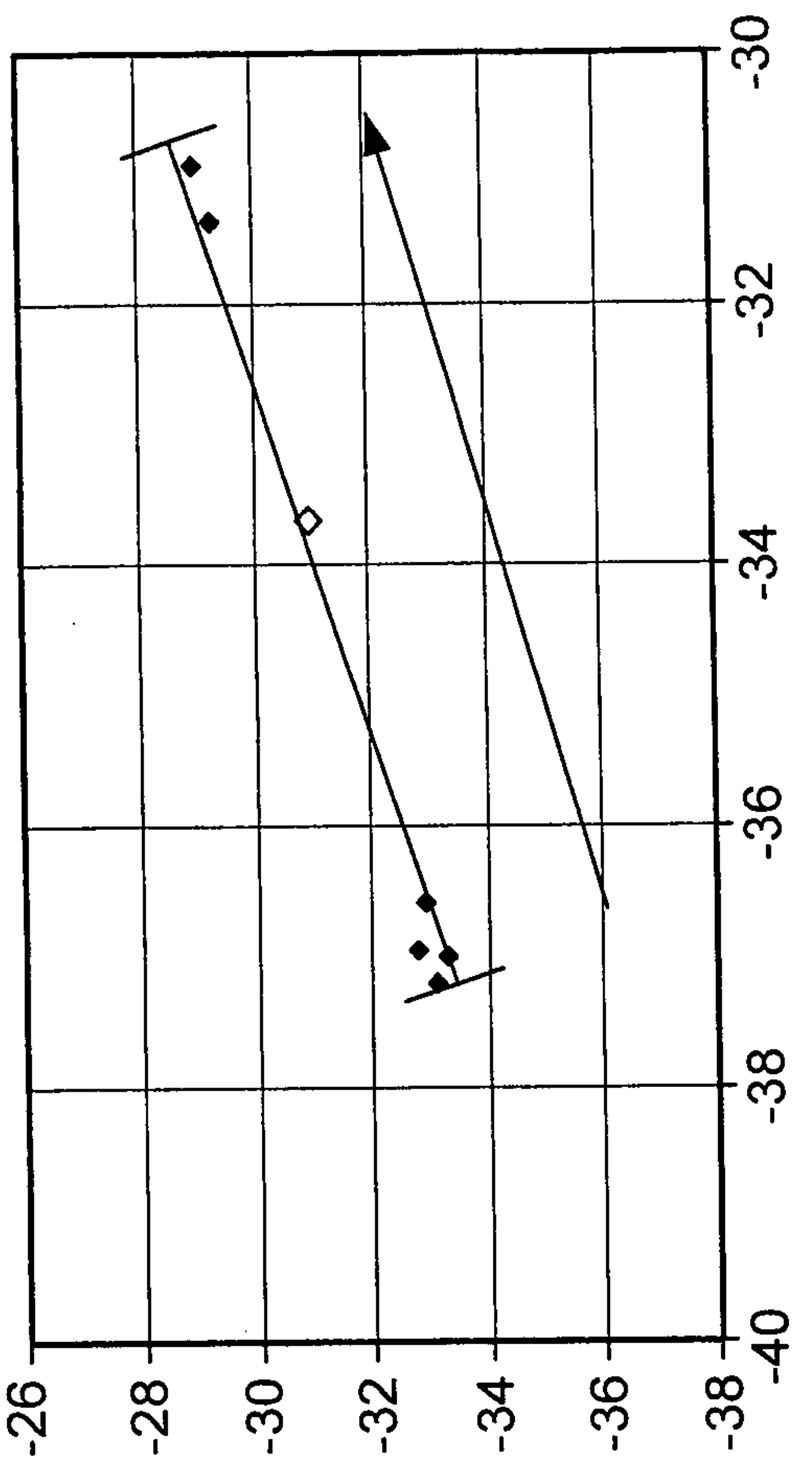


FIG. 282B

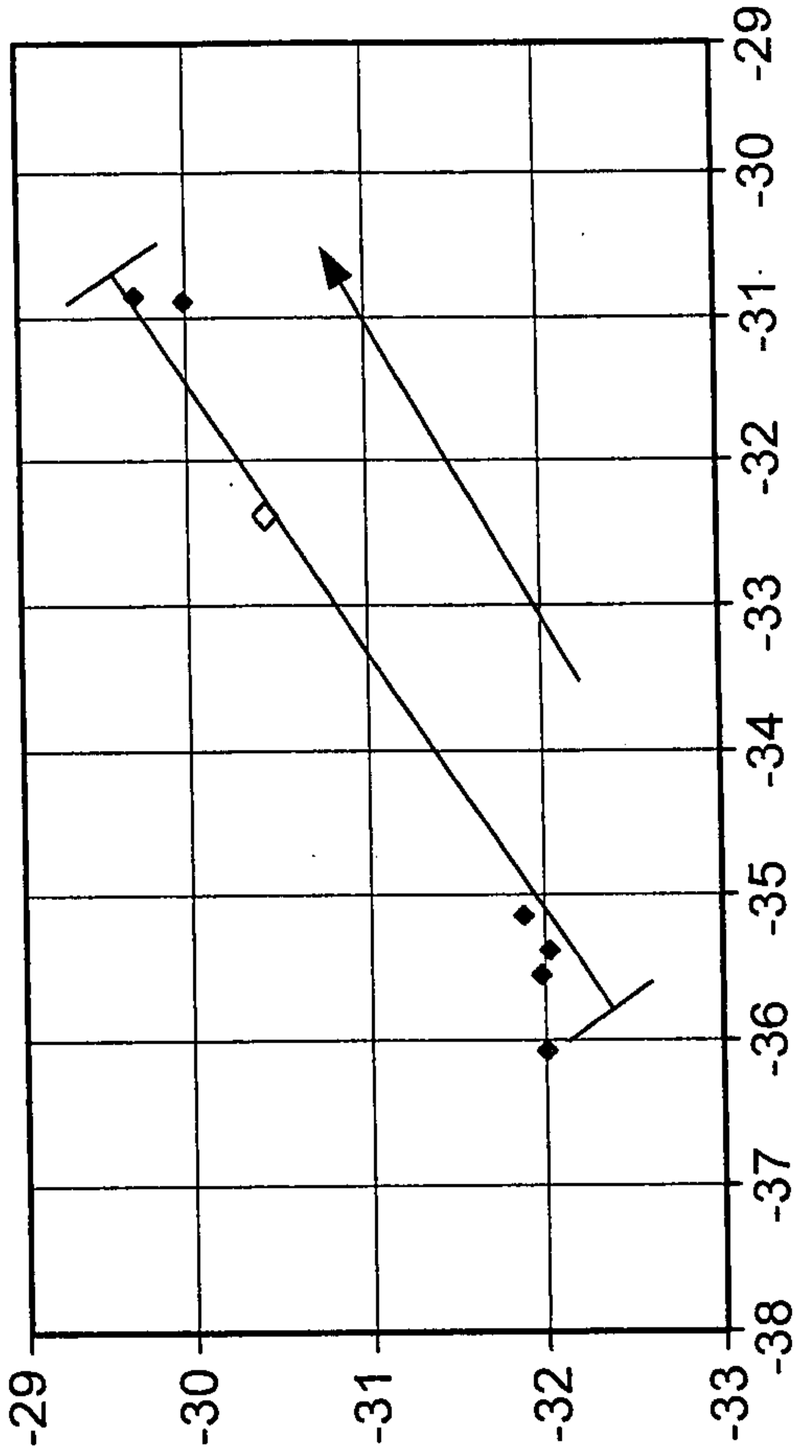


FIG. 282D

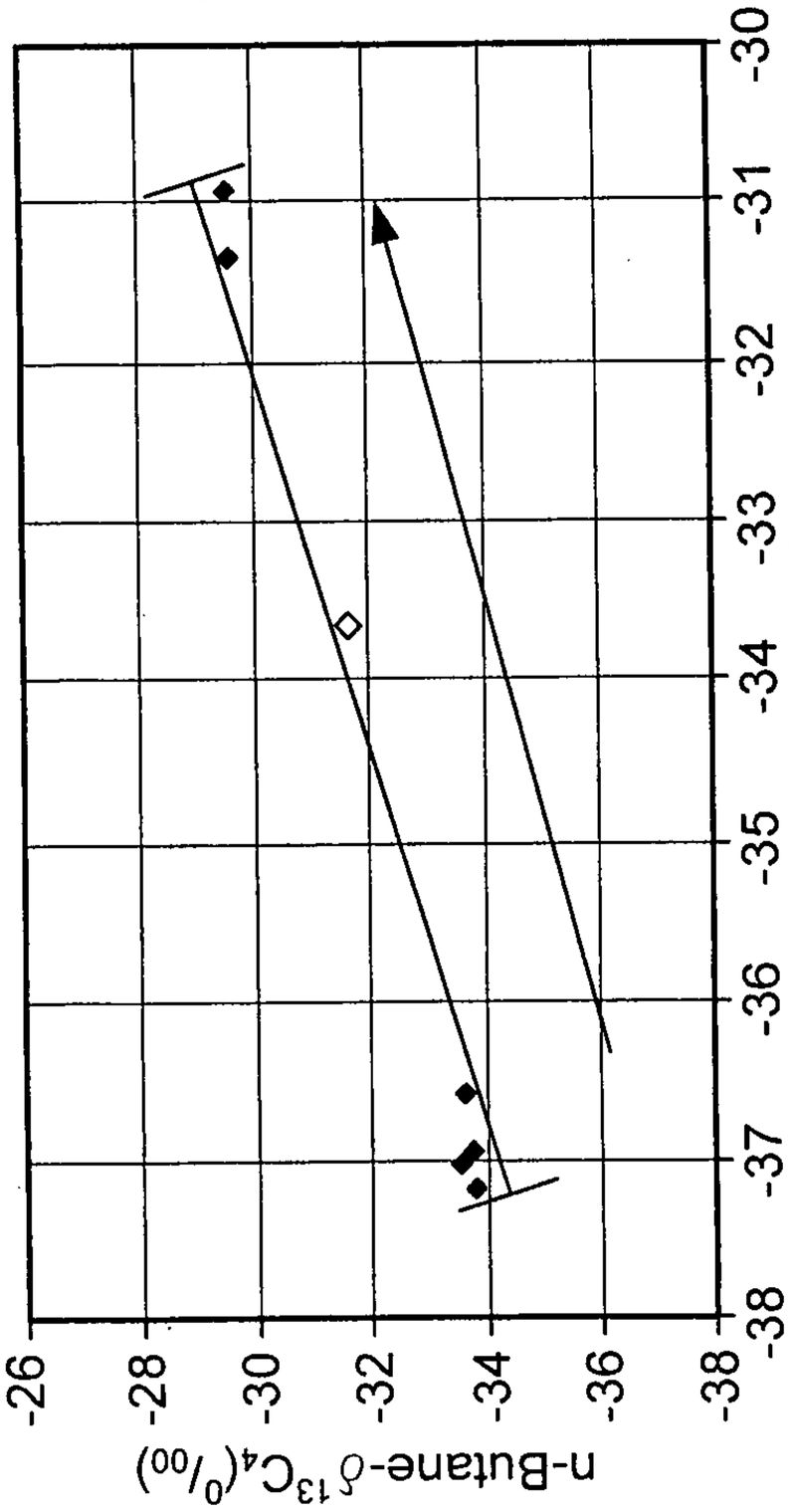


FIG. 282A

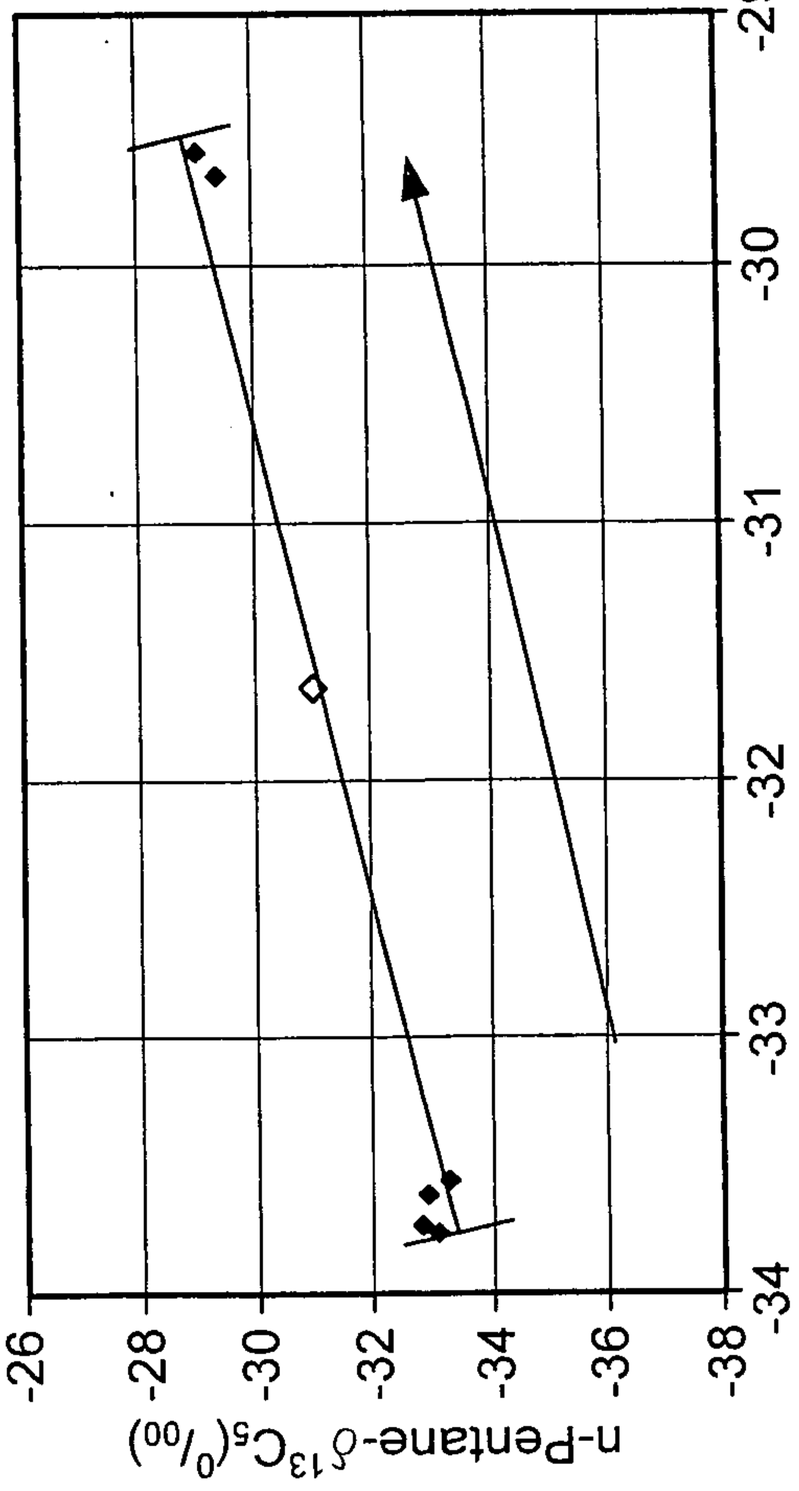


FIG. 282C

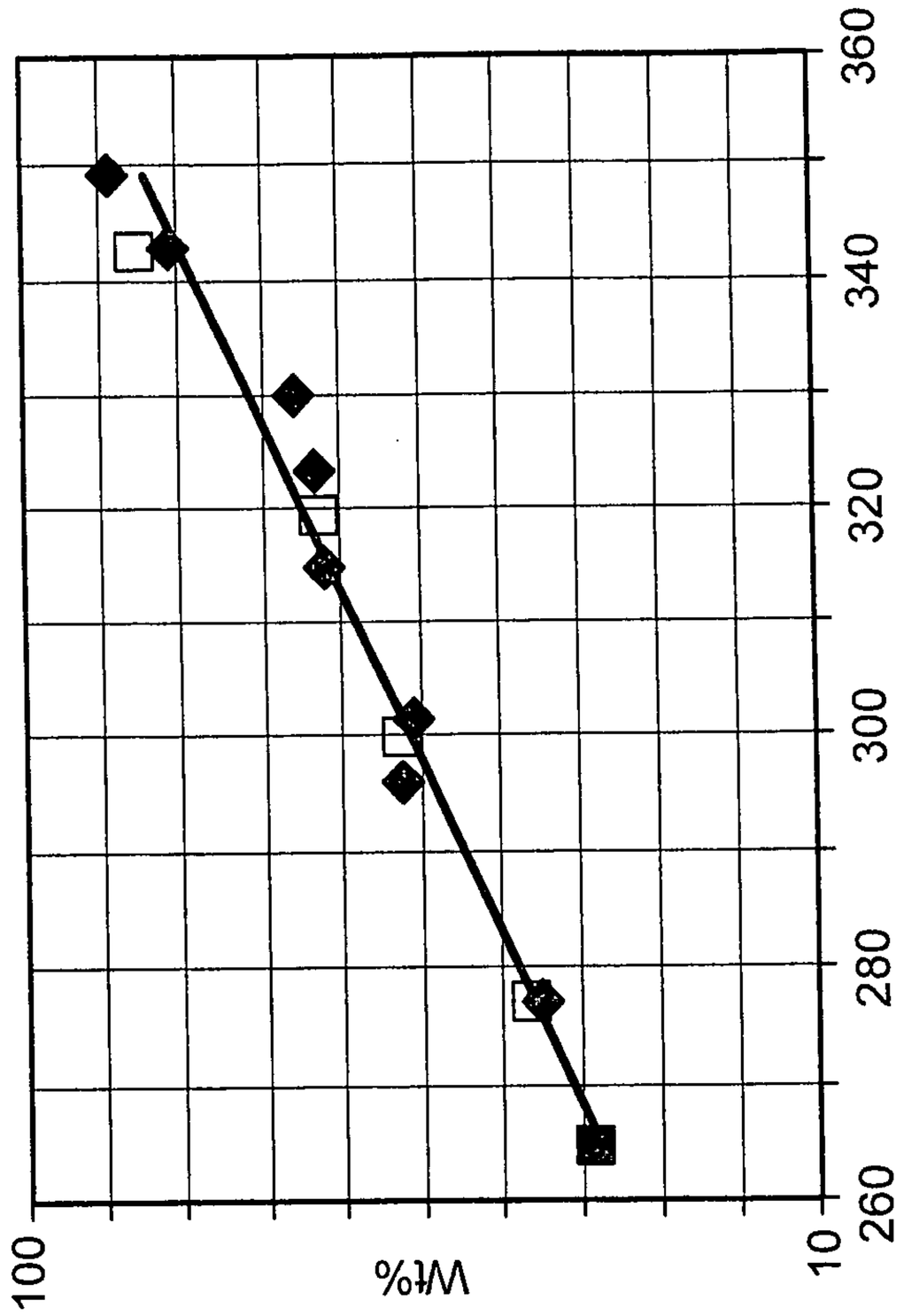


FIG. 284

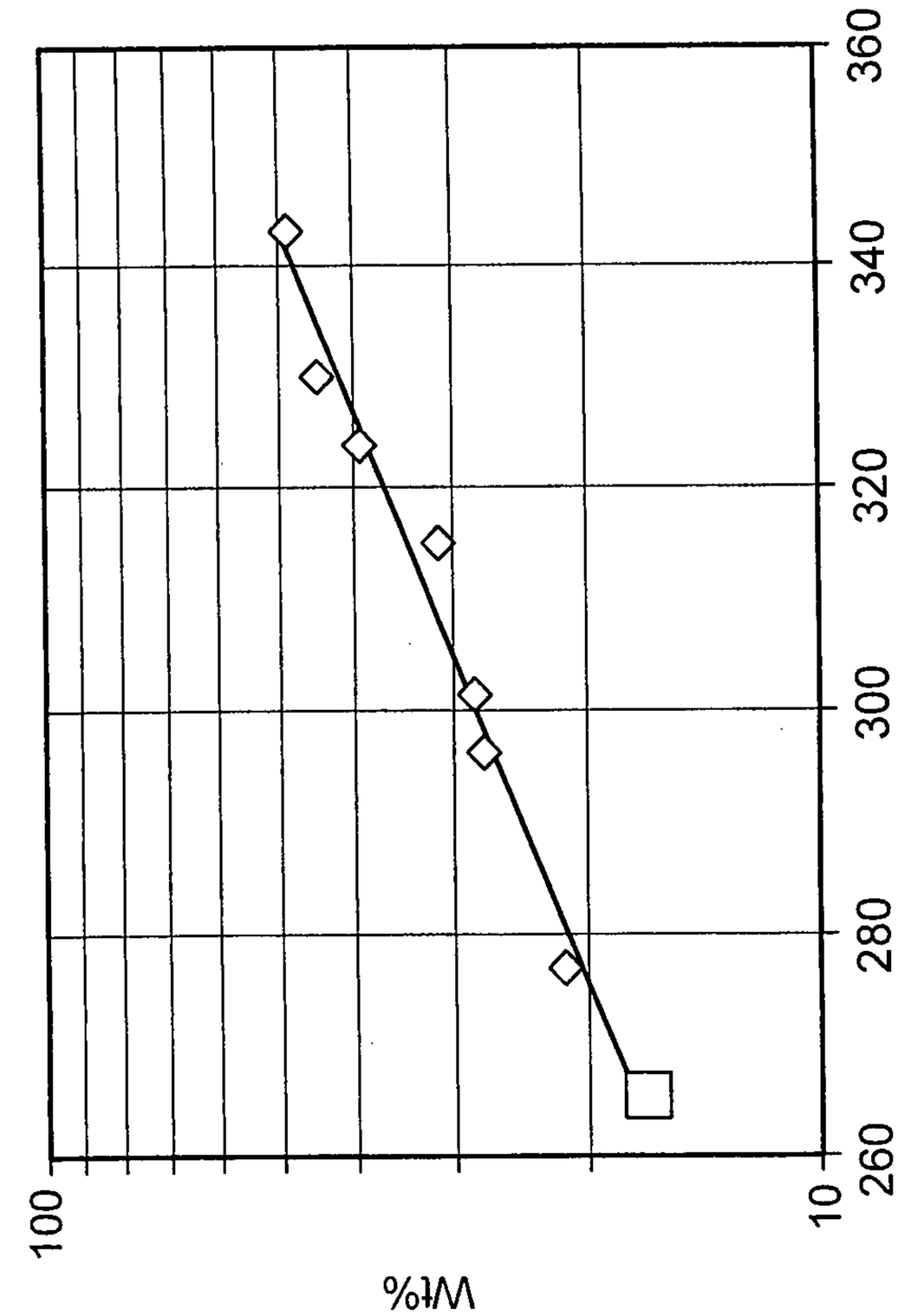


FIG. 283

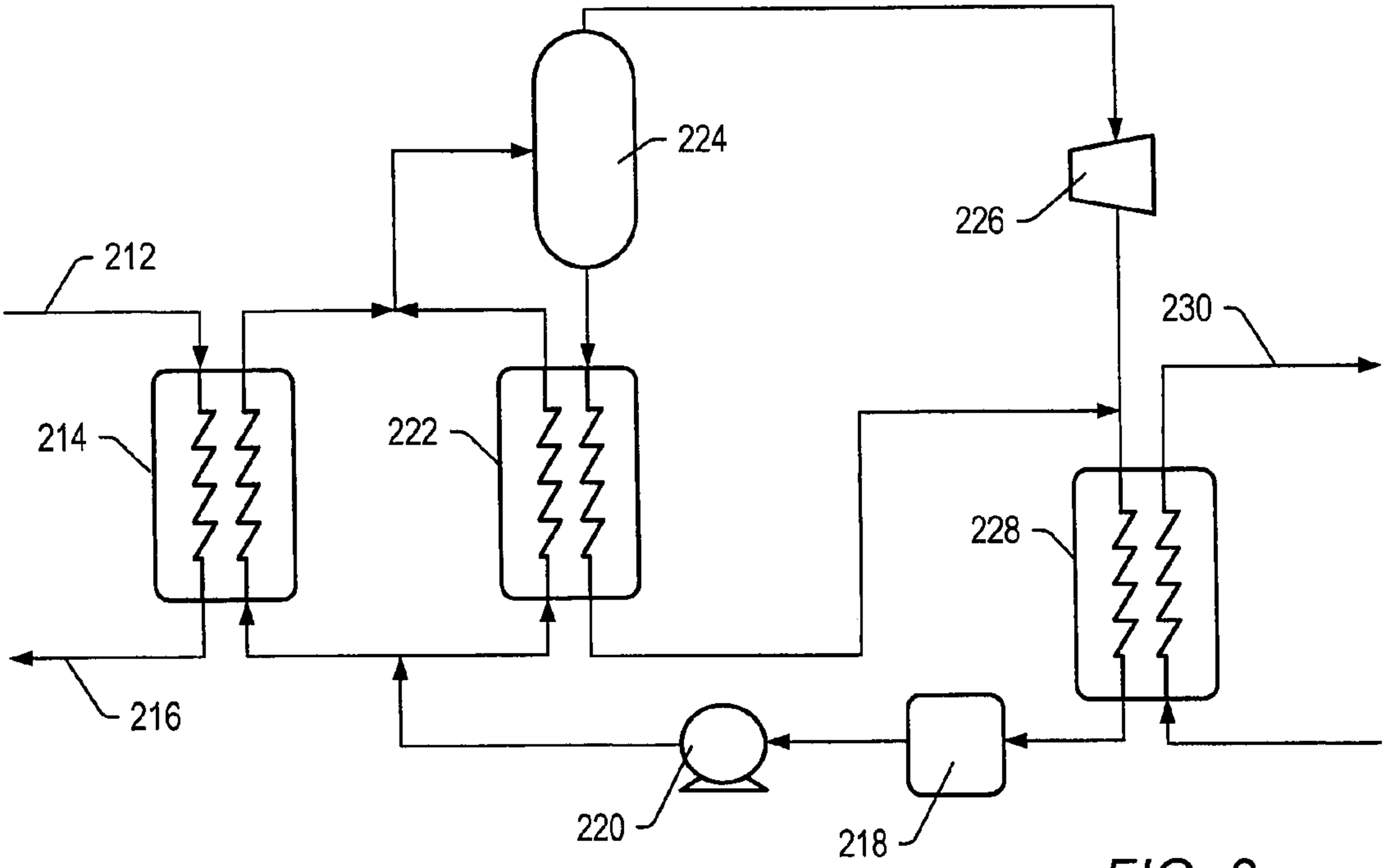


FIG. 3