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(54) **Title:** INSTALLATION AND USE OF REMOVABLE HEATERS IN A HYDROCARBON CONTAINING FORMATION

(57) **Abstract:** In an embodiment, a system may be used to heat a hydrocarbon containing formation. The system may include a heater placed in an opening in the formation. The system may allow heat to transfer from the heater to a part of the formation. The transferred heat may pyrolyze at least some hydrocarbons in the formation. The heater may be removable from the opening in the formation and redeployable in at least one alternative opening in the formation.

INSTALLATION AND USE OF REMOVABLE HEATERS IN A HYDROCARBON CONTAINING FORMATION

BACKGROUND OF THE INVENTION

1. Field of the Invention

The present invention relates generally to methods and systems for production of hydrocarbons, hydrogen, and/or other products from various hydrocarbon containing formations. Certain embodiments relate to the installation of redeployable heaters into hydrocarbon containing formations and/or the use of redeployable heaters in providing heat to hydrocarbon containing formations.

2. Description of Related Art

Hydrocarbons obtained from subterranean (e.g., sedimentary) formations are often used as energy resources, as feedstocks, and as consumer products. Concerns over depletion of available hydrocarbon resources and 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 within 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 within 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.

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 within a viscous oil within 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.

U.S. Patent No. 6,023,554 to Vinegar et al. describes an electric heating element that is positioned within 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.

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.

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

Combustion of a fuel may be used to heat a formation. Combusting a fuel to heat a formation may be more economical than using electricity to heat a formation. Several different types of heaters may use fuel combustion as a heat source that heats a formation. The combustion may take place in the formation, in a well, and/or near the surface. Combustion in the formation may be a fireflood. An oxidizer may be pumped into the formation. The oxidizer may be ignited to advance a fire front towards a production well. Oxidizer pumped into the formation may flow through the formation along fracture lines in the formation. Ignition of the oxidizer may not result in the fire front flowing uniformly through the formation.

A flameless combustor may be used to combust a fuel within a well. U.S. Patent Nos. 5,255,742 to Mikus; 5,404,952 to Vinegar et al.; 5,862,858 to Wellington et al.; and 5,899,269 to Wellington et al. describe flameless combustors. Flameless combustion may be accomplished by preheating a fuel and combustion air to a temperature above an auto-ignition temperature of the mixture. The fuel and combustion air may be mixed in a heating zone to combust. In the heating zone of the flameless combustor, a catalytic surface may be provided to lower the auto-ignition temperature of the fuel and air mixture.

Heat may be supplied to a formation from a surface heater. The surface heater may produce combustion gases that are circulated through wellbores to heat the formation. Alternatively, a surface burner may be used to heat a heat transfer fluid that is passed through a wellbore to heat the formation. Examples of fired heaters, or surface burners that may be used to heat a subterranean formation, are illustrated in U.S. Patent Nos. 6,056,057 to Vinegar et al. and 6,079,499 to Mikus et al.

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. In certain applications, it may be useful to have heaters placed in openings in the formation such that the heaters can be removed from the opening. In certain cases, the heaters can be redeployed into another opening in the formation. The heaters can also be removed to inspect and/or repair heaters. Being able to remove, replace, and/or redeploy a heater may favorably reduce equipment and/or operating costs for an in situ process.

SUMMARY OF THE INVENTION

One or more heaters may be disposed within an opening in a hydrocarbon containing formation such that the heaters transfer heat to the formation. In some embodiments, a heater may be placed in an open wellbore in the formation. An "open wellbore" in a formation may be a wellbore without casing or an "uncased wellbore." Heat may conductively and radiatively transfer from the heater to the formation. Alternatively, a heater may be placed within a heater well that may be packed with gravel, sand, and/or cement or a heater well with a casing.

In an embodiment, a heater may include a conductor-in-conduit heater. A conduit may be placed within an opening in the formation. A conductor may be placed within the conduit. The conductor may provide heat to at least a portion of the formation. A centralizer may be coupled to the conductor. The centralizer may inhibit movement of the conductor within the conduit. The conductor-in-conduit heater may be removable from the opening in the formation.

Application of an electrical current to the conductor may provide heat to a portion of the formation. The provided heat may be allowed to transfer from the conductor to a section of the formation. The heat may pyrolyze some hydrocarbons in the section of the formation.

In an embodiment, a conductor-in-conduit heater having a desired length may be assembled. A conductor may be placed within a conduit to form the conductor-in-conduit heater. Two or more conductor-in-conduit heaters may be coupled together to form a heater having the desired length. The conductors of the conductor-in-conduit heaters may be electrically coupled together. In addition, the conduits may be electrically coupled together. A desired length of the conductor-in-conduit may be placed in an opening in the hydrocarbon containing formation. In some embodiments, individual sections of the conductor-in-conduit heater may be coupled using shielded active gas welding.

In certain embodiments, a heater of a desired length may be assembled proximate the hydrocarbon containing formation. The assembled heater may then be coiled. The heater may be placed in the hydrocarbon containing formation by uncoiling the heater into the opening in the hydrocarbon containing formation.

In an embodiment, heat may be provided from one or more heaters to a portion of a formation. The provided heat may be allowed to transfer to a selected section of the formation. A mixture may be produced from the formation. The mixture may include at least some pyrolyzed hydrocarbons. In certain embodiments, a heater may be removable from an opening in the formation and redeployable in at least one alternative opening in the formation.

BRIEF DESCRIPTION OF THE DRAWINGS

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

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

FIG. 2 shows a schematic view of an embodiment of a portion of an in situ conversion system for treating a hydrocarbon containing formation.

FIG. 3 depicts an embodiment of a natural distributed combustor heat source.

FIG. 4 depicts an embodiment of an insulated conductor heat source.

FIG. 5 depicts an embodiment of three insulated conductor heaters placed within a conduit.

FIG. 6 depicts an embodiment of a conductor-in-conduit heat source in a formation.

FIG. 7 depicts a cross-sectional representation of an embodiment of a removable conductor-in-conduit heat source.

FIG. 8 depicts an embodiment of a wellhead with a conductor-in-conduit heat source.

FIG. 9 illustrates a schematic of an embodiment of a conductor-in-conduit heater, wherein a portion of the heater is placed substantially horizontally within a formation.

FIG. 10 illustrates an enlarged view of an embodiment of a junction of a conductor-in-conduit heater.

FIG. 11 illustrates a schematic of an embodiment of a conductor-in-conduit heater, wherein a portion of the heater is placed substantially horizontally within a formation.

FIG. 12 illustrates a schematic of an embodiment of a conductor-in-conduit heater, wherein a portion of the heater is placed substantially horizontally within a formation.

FIG. 13 illustrates a schematic of an embodiment of a conductor-in-conduit heater, wherein a portion of the heater is placed substantially horizontally within a formation.

FIG. 14 depicts an embodiment of a centralizer.

FIG. 15 depicts an embodiment of a centralizer.

FIG. 16 depicts an embodiment for assembling a conductor-in-conduit heat source and installing the heat source in a formation.

FIG. 17 depicts an embodiment of a conductor-in-conduit heat source to be installed in a formation.

FIG. 18 depicts an embodiment of a heat source in a formation.

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 OF THE INVENTION

The following description generally relates to systems and methods for treating a hydrocarbon containing formation (e.g., a formation containing coal (including lignite, sapropelic coal, etc.), oil shale, carbonaceous shale, shungites, kerogen, bitumen, oil, kerogen and oil in a low permeability matrix, heavy hydrocarbons, asphaltites, natural mineral waxes, formations wherein kerogen is blocking production of other hydrocarbons, etc.). Such formations may be treated to yield relatively high quality hydrocarbon products, hydrogen, and other products.

"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 within or adjacent to mineral matrices within 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 (e.g., hydrogen ("H_2"), nitrogen ("N_2"), carbon monoxide, carbon dioxide, hydrogen sulfide, water, and ammonia).

A "formation" includes one or more hydrocarbon containing layers, one or more non-hydrocarbon layers, an overburden, and/or an underburden. An "overburden" and/or an "underburden" includes one or more different types of impermeable materials. For example, overburden and/or underburden may include rock, shale, mudstone, or wet/tight carbonate (i.e., an impermeable carbonate without hydrocarbons). In some embodiments of in situ conversion processes, an overburden and/or an underburden may include a hydrocarbon containing layer or hydrocarbon containing layers that are relatively impermeable and are not subjected to temperatures during in situ conversion processing that results in significant characteristic changes of the hydrocarbon containing layers of the overburden and/or underburden. For example, an underburden may contain shale or mudstone. In some cases, the overburden and/or underburden may be somewhat permeable.

The terms "formation fluids" and "produced fluids" refer to fluids removed from a hydrocarbon containing formation and may include pyrolyzation fluid, synthesis gas, mobilized hydrocarbon, and water (steam). The term "mobilized fluid" refers to fluids within the formation that are able to flow because of thermal treatment of the formation. Formation fluids may include hydrocarbon fluids as well as non-hydrocarbon fluids.

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 within a conduit. A heat source may also include heat sources that generate heat by burning a fuel external to or within a formation, such as surface burners, downhole gas burners, flameless distributed combustors, and natural distributed combustors. In addition, it is envisioned that 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 transfer media 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. 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 (e.g., chemical reactions, solar energy, wind energy, biomass, or other sources of renewable energy). A chemical reaction may include an exothermic reaction (e.g., an oxidation reaction). A heat source may include a heater that provides heat to a zone proximate and/or surrounding a heating location such as a heater well.

A "heater" is any system 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 (e.g., natural distributed combustors), and/or combinations thereof. A "unit of heat sources" refers to a number of heat sources that form a template that is repeated to create a pattern of heat sources within a formation.

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 other cross-sectional shapes (e.g., circles, ovals, squares, rectangles, triangles, slits, or other regular or irregular shapes). As used herein, the terms "well" and "opening," when referring to an opening in the formation, may be used interchangeably with the term "wellbore."

"Natural distributed combustor" refers to a heater that uses an oxidant to oxidize at least a portion of the carbon in the formation to generate heat, and wherein the oxidation takes place in a vicinity proximate a wellbore. Most of the combustion products produced in the natural distributed combustor are removed through the wellbore.

"Orifices" refer to openings (e.g., 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.

"Reaction zone" refers to a volume of a hydrocarbon containing formation that is subjected to a chemical reaction such as an oxidation reaction.

"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. The term "self-controls" refers to controlling an output of a heater without external control of any type.

"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 (e.g., a relatively permeable formation such as a tar sands formation) that is reacted or reacting to form a pyrolyzation fluid.

"Condensable hydrocarbons" are hydrocarbons that condense at 25 °C at 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.

Hydrocarbons in formations may be treated in various ways to produce many different products. In certain embodiments, such formations may be treated in stages. FIG. 1 illustrates several stages of heating a hydrocarbon containing formation. FIG. 1 also depicts an example of yield (barrels of oil equivalent per ton) (y axis) of formation fluids from a hydrocarbon containing formation versus temperature (°C) (x axis) of the formation (as the formation is heated at a relatively low rate).

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 a hydrocarbon containing formation is initially heated, hydrocarbons in the formation may desorb adsorbed methane. The desorbed methane may be produced from the formation. If the hydrocarbon containing formation is heated further, water within the hydrocarbon containing formation may be vaporized. Water may occupy, in some hydrocarbon containing formations, between about 10 % and about 50 % of the pore volume in the formation. In other formations, water may occupy larger or smaller portions of the pore volume. Water typically is vaporized in a formation between about 160 °C and about 285 °C for pressures of about 6 bars absolute to 70 bars absolute. In some embodiments, the vaporized water may produce wettability changes in the formation and/or increase 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 may be produced from the formation. In other embodiments, the vaporized water may be 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 may increase the storage space for hydrocarbons within the pore volume.

After stage 1 heating, the formation may be heated further, such that a temperature within the formation reaches (at least) an initial pyrolyzation temperature (e.g., a temperature at the lower end of the temperature range shown as stage 2). Hydrocarbons within the formation may be pyrolyzed throughout stage 2. A pyrolysis temperature range may vary depending on types of hydrocarbons within the formation. A pyrolysis temperature range may include temperatures between about 250 °C and about 900 °C. A pyrolysis temperature range for producing desired products may extend through only a portion of the total pyrolysis temperature range. In some embodiments, a pyrolysis temperature range for producing desired products may include temperatures between about 250 °C and about 400 °C. If a temperature of hydrocarbons in a formation is slowly raised through a temperature range from about 250 °C to about 400 °C, production of pyrolysis products may be substantially complete when the temperature approaches 400 °C. 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 a pyrolysis temperature range.

In some in situ conversion embodiments, a temperature of the hydrocarbons to be subjected to pyrolysis may not be slowly increased throughout a temperature range from about 250 °C to about 400 °C. The hydrocarbons in the formation may be heated to a desired temperature (e.g., about 325 °C). Other temperatures may be selected as the desired temperature. Superposition of heat from heat sources may allow 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 hydrocarbons may be maintained substantially at the desired temperature until pyrolysis declines such that production of desired formation fluids from the formation becomes uneconomical.

Formation fluids including pyrolyzation fluids may be produced from the formation. The pyrolyzation fluids may include, but are not limited to, hydrocarbons, hydrogen, carbon dioxide, carbon monoxide, hydrogen sulfide, ammonia, nitrogen, water, and mixtures thereof. As the temperature of the formation increases, the amount of condensable hydrocarbons in the produced formation fluid tends to decrease. At high temperatures, the formation may produce mostly methane and/or hydrogen. If a 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.

After pyrolysis of hydrocarbons, a large amount of carbon and some hydrogen may still be present in the formation. A significant portion of remaining carbon 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 within a temperature range from about 400 °C to about 1200 °C. The temperature of the formation when the synthesis gas generating fluid is introduced to the formation may determine the composition of synthesis gas produced within the formation. If a synthesis gas generating fluid is introduced into a formation at a temperature sufficient to allow synthesis gas generation, synthesis gas may be generated within the formation. The generated synthesis gas may be removed from the formation through a production well or production wells. A large volume of synthesis gas may be produced during generation of synthesis gas.

FIG. 2 shows a schematic view of an embodiment of a portion of an in situ conversion system for treating a hydrocarbon containing formation. Heat sources 100 may be placed within at least a portion of the hydrocarbon containing formation. Heat sources 100 may include, for example, electric heaters such as insulated conductors, conductor-in-conduit heaters, surface burners, flameless distributed combustors, and/or natural distributed combustors. Heat sources 100 may also include other types of heaters. Heat sources 100 may provide heat to at least a portion of a hydrocarbon containing formation. Energy may be supplied to the heat sources 100 through supply lines 102. The supply lines may be structurally different depending on the type of heat source or heat sources being used to heat the formation. Supply lines for heat sources may transmit electricity for electric heaters, may transport fuel for combustors, or may transport heat exchange fluid that is circulated within the formation.

Production wells 104 may be used to remove formation fluid from the formation. Formation fluid produced from production wells 104 may be transported through collection piping 106 to treatment facilities 108. Formation fluids may also be produced from heat sources 100. For example, fluid may be produced from heat sources 100 to control pressure within the formation adjacent to the heat sources. Fluid produced from heat sources 100 may be transported through tubing or piping to collection piping 106 or the produced fluid may be transported through tubing or piping directly to treatment facilities 108. Treatment facilities 108 may include separation units, reaction units, upgrading units, fuel cells, turbines, storage vessels, and other systems and units for processing produced formation fluids.

An in situ conversion system for treating hydrocarbons may include barrier wells 110. In certain embodiments, barrier wells 110 may include freeze wells. In some embodiments, barriers may be used to inhibit migration of fluids (e.g., generated fluids and/or groundwater) into and/or out of a portion of a formation undergoing an in situ conversion process. Barriers may include, but are not limited to naturally occurring portions (e.g., overburden and/or underburden), freeze wells, frozen barrier zones, low temperature barrier zones, grout walls, sulfur wells, dewatering wells, injection wells, 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, sheets driven into the formation, or combinations thereof.

As shown in FIG. 2, in addition to heat sources 100, one or more production wells 104 will typically be placed within the portion of the hydrocarbon containing formation. Formation fluids may be produced through production well 104. In some embodiments, production well 104 may include a heat source. The heat source may heat the portions of the formation at or near the production well and allow for vapor phase removal of formation fluids. The need for high temperature pumping of liquids from the production well may be reduced or eliminated. Avoiding or limiting high temperature pumping of liquids may significantly decrease production costs. 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, and/or (3) increase formation permeability at or proximate the production well. In some in situ conversion process embodiments, an amount of heat supplied to production wells is significantly less than an amount of heat applied to heat sources that heat the formation.

In an embodiment, a hydrocarbon containing formation may be heated with a natural distributed combustor system located in the formation. The generated heat may be allowed to transfer to a selected section of the formation. A natural distributed combustor may oxidize hydrocarbons in a formation in the vicinity of a wellbore to provide heat to a selected section of the formation.

A temperature sufficient to support oxidation may be at least about 200 °C or 250 °C. The temperature sufficient to support oxidation will tend to vary depending on many factors (e.g., a composition of the hydrocarbons in the hydrocarbon containing formation, water content of the formation, and/or type and amount of oxidant). Some water may be removed from the formation prior to heating. For example, the water may be pumped from the formation by dewatering wells. The heated portion of the formation may be near or substantially adjacent to an opening in the hydrocarbon containing formation. The opening in the formation may be a heater well formed in the formation. The heated portion of the hydrocarbon containing formation may extend radially from the opening to a width of about 0.3 m to about 1.2 m. The width, however, may also be less than about 0.9 m. A width of the heated portion may vary with time. In certain embodiments, the variance depends on factors including a width of formation necessary to generate sufficient heat during oxidation of carbon to maintain the oxidation reaction without providing heat from an additional heat source.

After the portion of the formation reaches a temperature sufficient to support oxidation, an oxidizing fluid may be provided into the opening to oxidize at least a portion of the hydrocarbons at a reaction zone or a heat source zone within the formation. Oxidation of the hydrocarbons will generate heat at the reaction zone. The generated heat will in most embodiments transfer from the reaction zone to a pyrolysis zone in the formation. In certain embodiments, the generated heat transfers at a rate between about 650 watts per meter and 1650 watts per meter as measured along a depth of the reaction zone. Upon oxidation of at least some of the hydrocarbons in the formation, energy supplied to the heater for initially heating the formation to the temperature sufficient to support oxidation may be reduced or turned off. Energy input costs may be significantly reduced using natural distributed combustors, thereby providing a significantly more efficient system for heating the formation.

In an embodiment, a conduit may be disposed in the opening to provide oxidizing fluid into the opening. The conduit may have flow orifices or other flow control mechanisms (i.e., slits, venturi meters, valves, etc.) to allow the oxidizing fluid to enter the opening. The term "orifices" includes openings having a wide variety of cross-sectional shapes including, but not limited to, circles, ovals, squares, rectangles, triangles, slits, or other regular or irregular shapes. The flow orifices may be critical flow orifices in some embodiments. The flow orifices may provide a substantially constant flow of oxidizing fluid into the opening, regardless of the pressure in the opening.

The flow of oxidizing fluid into the opening may be controlled such that a rate of oxidation at the reaction zone is controlled. Transfer of heat between incoming oxidant and outgoing oxidation products may heat the oxidizing fluid. The transfer of heat may also maintain the conduit below a maximum operating temperature of the conduit.

FIG. 3 illustrates an embodiment of a natural distributed combustor that may heat a hydrocarbon containing formation. Conduit 112 may be placed into opening 114 in hydrocarbon layer 116. Conduit 112 may have inner conduit 118. Oxidizing fluid source 120 may provide oxidizing fluid 122 into inner conduit 118. Inner conduit 118 may have critical flow orifices 124 along its length. Critical flow orifices 124 may be disposed in a helical pattern (or any other pattern) along a length of inner conduit 118 in opening 114. For example, critical flow orifices 124 may be arranged in a helical pattern with a distance of about 1 m to about 2.5 m between adjacent orifices. Inner conduit 118 may be sealed at the bottom. Oxidizing fluid 122 may be provided into opening 114 through critical flow orifices 124 of inner conduit 118.

Critical flow orifices 124 may be designed such that substantially the same flow rate of oxidizing fluid 122 may be provided through each critical flow orifice. Critical flow orifices 124 may also provide substantially uniform flow of oxidizing fluid 122 along a length of inner conduit 118. Such flow may provide substantially uniform heating of hydrocarbon layer 116 along the length of inner conduit 118.

Packing material 126 may enclose conduit 112 in overburden 128 of the formation. Packing material 126 may inhibit flow of fluids from opening 114 to surface 130. Packing material 126 may include any material that inhibits flow of fluids to surface 130 such as cement or consolidated sand or gravel. A conduit or opening through the packing may provide a path for oxidation products to reach the surface.

Oxidation products 132 typically enter conduit 112 from opening 114. Oxidation products 132 may include carbon dioxide, oxides of nitrogen, oxides of sulfur, carbon monoxide, and/or other products resulting from a reaction of oxygen with hydrocarbons and/or carbon. Oxidation products 132 may be removed through conduit 112 to surface 130. Oxidation products 132 may flow along a face of reaction zone 134 in opening 114 until proximate an upper end of opening 114 where oxidation products 132 may flow into conduit 112. Oxidation products 132 may also be removed through one or more conduits disposed in opening 114 and/or in hydrocarbon layer 116. For example, oxidation products 132 may be removed through a second conduit disposed in opening 114. Removing oxidation products 132 through a conduit may inhibit oxidation products 132 from flowing to a production well disposed in the formation. Critical flow orifices 124 may also inhibit oxidation products 132 from entering inner conduit 118.

A flow rate of oxidation products 132 may be balanced with a flow rate of oxidizing fluid 122 such that a substantially constant pressure is maintained within opening 114. For a 100 m length of heated section, a flow rate of oxidizing fluid may be between about 0.5 standard cubic meters per minute to about 5 standard cubic meters per minute, or about 1.0 standard cubic meter per minute to about 4.0 standard cubic meters per minute, or, for example, about 1.7 standard cubic meters per minute. A flow rate of oxidizing fluid into the formation may be incrementally increased during use to accommodate expansion of the reaction zone. A pressure in the opening may be, for example, about 8 bars absolute. Oxidizing fluid 122 may oxidize at least a portion of the hydrocarbons in heated portion 136 of hydrocarbon layer 116 at reaction zone 134. Heated portion 136 may have been initially heated to a temperature sufficient to support oxidation by an electric heater. In some embodiments, an electric heater may be placed inside or strapped to the outside of inner conduit 118.

In certain embodiments, controlling the pressure within opening 114 may inhibit oxidation products and/or oxidation fluids from flowing into the pyrolysis zone of the formation. In some instances, pressure within opening 114 may be controlled to be slightly greater than a pressure in the formation to allow fluid within the opening to pass into the formation but to inhibit formation of a pressure gradient that allows the transport of the fluid a significant distance into the formation.

Although the heat from the oxidation is transferred to the formation, oxidation products 132 (and excess oxidation fluid such as air) may be inhibited from flowing through the formation and/or to a production well within the formation. Instead, oxidation products 132 and/or excess oxidation fluid may be removed from the formation. In some embodiments, the oxidation product and/or excess oxidation fluid are removed through conduit 112. Removing oxidation product and/or excess oxidation fluid may allow heat from oxidation reactions to transfer to the pyrolysis zone without significant amounts of oxidation product and/or excess oxidation fluid entering the pyrolysis zone.

Heat generated at reaction zone 134 may transfer by thermal conduction to selected section 138 of hydrocarbon layer 116. In addition, generated heat may transfer from a reaction zone to the selected section to a lesser extent by convective heat transfer. Selected section 138, sometimes referred as the "pyrolysis zone," may be substantially adjacent to reaction zone 134. Removing oxidation product (and excess oxidation fluid such as air) may allow the pyrolysis zone to receive heat from the reaction zone without being exposed to oxidation product, or oxidants, that are in the reaction zone. Oxidation product and/or oxidation fluids may cause the formation of undesirable products if they are present in the pyrolysis zone. Removing oxidation product and/or oxidation fluids may allow a reducing environment to be maintained in the pyrolysis zone.

In some embodiments, a second conduit may be placed in opening 114 of a natural distributed combustor heater. The second conduit may be used to remove oxidation products from opening 114. The second conduit may have orifices disposed along its length. In certain embodiments, oxidation products may be removed from an upper region of opening 114 through orifices disposed on the second conduit. The orifices may be disposed along the length of the second conduit such that more oxidation products are removed from the upper region of opening 114.

In certain natural distributed combustor embodiments, the orifices on the second conduit may face away from critical flow orifices 124 on inner conduit 118. This orientation may inhibit oxidizing fluid provided through inner conduit 118 from passing directly into the second conduit.

An electric heater may heat a portion of the hydrocarbon containing formation to a temperature sufficient to support oxidation of hydrocarbons. The portion may be proximate or substantially adjacent to the opening in the formation. The portion may radially extend a width of less than approximately 1 m from the opening. An oxidizing fluid may be provided to the opening for oxidation of hydrocarbons. Oxidation of the hydrocarbons may heat the hydrocarbon containing formation in a process of natural distributed combustion. Electrical current applied to the electric heater may subsequently be reduced or may be turned off. Natural distributed combustion may be used in conjunction with an electric heater to provide a reduced input energy cost method to heat the hydrocarbon containing formation compared to using only an electric heater.

An insulated conductor heater may be a heater element of a heat source. In an embodiment of an insulated conductor heater, the insulated conductor heater is a mineral insulated cable or rod. An insulated conductor heater may be placed in an opening in a hydrocarbon containing formation. The insulated conductor heater may be placed in an uncased opening in the hydrocarbon containing formation. Placing the heater in an uncased opening in the hydrocarbon containing formation may allow heat transfer from the heater to the formation by radiation as well as conduction. Using an uncased opening may facilitate retrieval of the heater from the well, if necessary. Using an uncased opening may significantly reduce heater capital cost by eliminating a need for a portion of casing able to withstand high temperature conditions. In some heater embodiments, an insulated conductor heater may be placed within a casing in the formation; may be cemented within the formation; or may be packed in an opening with sand, gravel, or other fill material. The insulated conductor heater may be supported on a support member positioned within the opening. The support member may be a cable, rod, or a conduit (e.g., a pipe). The support member may be made of a metal, ceramic, inorganic material, or combinations thereof. Portions of a support member may be exposed to formation fluids and heat during use, so the support member may be chemically resistant and thermally resistant.

Ties, spot welds, and/or other types of connectors may be used to couple the insulated conductor heater to the support member at various locations along a length of the insulated conductor heater. The support member may be attached to a wellhead at an upper surface of the formation. In an embodiment of an insulated conductor heater, the insulated conductor heater is designed to have sufficient structural strength so that a support member is not needed. The insulated conductor heater will in many instances have some flexibility to inhibit thermal expansion damage when heated or cooled.

In certain embodiments, insulated conductor heaters may be placed in wellbores without support members and/or centralizers. An insulated conductor heater without support members and/or centralizers may have a suitable combination of temperature and corrosion resistance, creep strength, length, thickness (diameter), and metallurgy that will inhibit failure of the insulated conductor during use.

A number of companies manufacture insulated conductor heaters. Such manufacturers include, but are not limited to, MI Cable Technologies (Calgary, Alberta), Pyrotenax Cable Company (Trenton, Ontario), Idaho Laboratories Corporation (Idaho Falls, Idaho), and Watlow (St. Louis, MO). As an example, an insulated conductor heater may be ordered from Idaho Laboratories as cable model 355-A90-310-"H" 30'/750'/30' with Inconel 600 sheath for the cold pins, three-phase Y configuration, and bottom jointed conductors. The specification for the heater may also include 1000 VAC, 1400 °F quality cable. The designator 355 specifies the cable OD (0.355"); A90 specifies the conductor material; 310 specifies the heated zone sheath alloy (SS 310); "H" specifies the MgO mix; and 30'/750'/30' specifies about a 230 m heated zone with cold pins top and bottom having about 9 m lengths. A similar part number with the same specification using high temperature Standard purity MgO cable may be ordered from Pyrotenax Cable Company.

One or more insulated conductor heaters may be placed within an opening in a formation to form a heater or heaters. Electrical current may be passed through each insulated conductor heater in the opening to heat the formation. Alternatively, electrical current may be passed through selected insulated conductor heaters in an opening. The unused conductors may be backup heaters. Insulated conductor heaters may be electrically coupled to a power source in any convenient manner. Each end of an insulated conductor heater may be coupled to lead-in cables that pass through a wellhead. Such a configuration typically has a 180° bend (a "hairpin" bend) or turn located near a bottom of the heater. An insulated conductor heater that includes a 180° bend or turn may not require a bottom termination, but the 180° bend or turn may be an electrical and/or structural weakness in the heater. Insulated conductor heaters may be electrically coupled together in series, in parallel, or in series and parallel combinations. In some embodiments of heaters, electrical current may pass into the conductor of an insulated conductor heater and may be returned through the sheath of the insulated conductor heater.

In the embodiment of a heater depicted in FIG. 4, three insulated conductor heaters 140 are electrically coupled in a 3-phase Y configuration to a power supply. The power supply may provide 60 cycle AC current to the electrical conductors. No bottom connection may be required for the insulated conductor heaters. Alternatively, all three conductors of the three-phase circuit may be connected together near the bottom of a heater opening. The connection may be made directly at ends of heating sections of the insulated conductor heaters or at ends of cold pins coupled to the heating sections at the bottom of the insulated conductor heaters. The bottom connections may be made with insulator filled and sealed canisters or with epoxy filled canisters. The insulator may be the same composition as the insulator used as the electrical insulation.

The three insulated conductor heaters depicted in FIG. 4 may be coupled to support member 142 using centralizers 144. Alternatively, the three insulated conductor heaters may be strapped directly to the support tube using metal straps. Centralizers 144 may maintain a location or inhibit movement of insulated conductor heaters 140 on support member 142. Centralizers 144 may be made of metal, ceramic, or combinations thereof. The metal may be stainless steel or any other type of metal able to withstand a corrosive and hot environment. In some embodiments, centralizers 144 may be bowed metal strips welded to the support member at distances less than about 6 m. A ceramic used in centralizer 144 may be, but is not limited to, Al_2O_3, MgO, or other insulator. Centralizers 144 may maintain a location of insulated conductor heaters 140 on support member 142 such that movement of insulated conductor heaters is inhibited at operating temperatures of the insulated conductor heaters. Insulated conductor heaters 140 may also be somewhat flexible to withstand expansion of support member 142 during heating.

Support member 142, insulated conductor heater 140, and centralizers 144 may be placed in opening 114 in hydrocarbon layer 116. Insulated conductor heaters 140 may be coupled to bottom conductor junction 146 using cold pin transition conductor 148. Bottom conductor junction 146 may electrically couple insulated conductor heaters 140 to each other. Bottom conductor junction 146 may include materials that are electrically conducting and do not melt at temperatures found in opening 114. Cold pin transition conductor 148 may be an insulated conductor heater having lower electrical resistance than insulated conductor heater 140.

Lead-in conductor 150 may be coupled to wellhead 152 to provide electrical power to insulated conductor heater 140. Lead-in conductor 150 may be made of a relatively low electrical resistance conductor such that relatively little heat is generated from electrical current passing through lead-in conductor 150. In some embodiments, the lead-in conductor is a rubber or polymer insulated stranded copper wire. In some embodiments, the lead-in conductor is a mineral-insulated conductor with a copper core. Lead-in conductor 150 may couple to wellhead 152 at surface 130 through a sealing flange located between overburden 128 and surface 130. The sealing flange may inhibit fluid from escaping from opening 114 to surface 130.

In some embodiments, reinforcing material 154 may secure overburden casing 156 to overburden 128. In an embodiment of a heater, overburden casing is a 7.6 cm (3 inch) diameter carbon steel, schedule 40 pipe. Reinforcing material 154 may include, for example, Class G or Class H Portland cement mixed with silica flour for improved high temperature performance, slag or silica flour, and/or a mixture thereof (e.g., about 1.58 grams per cubic centimeter slag/silica flour). In some heater embodiments, reinforcing material 154 extends radially a width of from about 5 cm to about 25 cm. In some embodiments, reinforcing material 154 may extend radially a width of about 10 cm to about 15 cm.

In certain embodiments, one or more conduits may be provided to supply additional components (e.g., nitrogen, carbon dioxide, reducing agents such as gas containing hydrogen, etc.) to formation openings, to bleed off fluids, and/or to control pressure. Formation pressures tend to be highest near heating sources. Providing pressure control equipment in heaters may be beneficial. In some embodiments, adding a reducing agent proximate the heating source assists in providing a more favorable pyrolysis environment (e.g., a higher hydrogen partial pressure). Since permeability and porosity tend to increase more quickly proximate the heating source, it is often optimal to add a reducing agent proximate the heating source so that the reducing agent can more easily move into the formation.

Conduit 158, depicted in FIG. 4, may be provided to add gas from gas source 160, through valve 162, and into opening 114. Conduit 158 and valve 164 may be used at different times to bleed off pressure and/or control pressure proximate opening 114. It is to be understood that any of the heating sources described herein may also be equipped with conduits to supply additional components, bleed off fluids, and/or to control pressure.

As shown in FIG. 4, support member 142 and lead-in conductor 150 may be coupled to wellhead 152 at surface 130 of the formation. Surface conductor 166 may enclose reinforcing material 154 and couple to wellhead 152. Embodiments of surface conductor 166 may have an outer diameter of about 10.16 cm to about 30.48 cm or, for example, an outer diameter of about 22 cm. Embodiments of surface conductors may extend to depths of approximately 3m to approximately 515 m into an opening in the formation. Alternatively, the surface conductor may extend to a depth of approximately 9 m into the opening. Electrical current may be supplied from a power source to insulated conductor heater 140 to generate heat. As an example, a voltage of about 330 volts and a current of about 266 amps are supplied to insulated conductor heater 140 to generate a heat of about 1150 watts/meter in insulated conductor heater 140. Heat generated from the three insulated conductor heaters 140 may transfer (e.g., by radiation) within opening 114 to heat at least a portion of hydrocarbon layer 116.

Heat generated by an insulated conductor heater may heat at least a portion of a hydrocarbon containing formation. In some embodiments, heat may be transferred to the formation substantially by radiation of the generated heat to the formation. Some heat may be transferred by conduction or convection of heat due to gases present in the opening. The opening may be an uncased opening. An uncased opening eliminates cost associated with thermally cementing the heater to the formation, costs associated with a casing, and/or costs of packing a heater within an opening. In addition, heat transfer by radiation is typically more efficient than by conduction, so the heaters may be operated at lower temperatures in an open wellbore. Conductive heat transfer during initial operation of a heater may be enhanced by the addition of a gas in the opening. The gas may be maintained at a pressure up to about 27 bars absolute. The gas may include, but is not limited to, carbon dioxide and/or helium. An insulated conductor heater in an open wellbore may advantageously be free to expand or contract to accommodate thermal expansion and contraction. An insulated conductor heater may advantageously be removable or redeployable from an open wellbore.

In an embodiment, an insulated conductor heater may be installed or removed using a spooling assembly. More than one spooling assembly may be used to install both the insulated conductor and a support member simultaneously. U.S. Patent No. 4,572,299 issued to Van Egmond et al. describes spooling an electric heater into a well. Alternatively, the support member may be installed using a coiled tubing unit. Coiled tubing techniques are described in PCT Patent Nos. WO/0043630 and WO/0043631. The heaters may be un-spooled and connected to the support member as the support member is inserted into the well. The heater and the support member may be un-spooled from the spooling assemblies. Spacers may be coupled to the support member and the heater along a length of the support member. Additional spooling assemblies may be used for additional electric heater elements.

In an in situ conversion process embodiment, a heater may be installed in a substantially horizontal wellbore. Installing a heater in a wellbore (whether vertical or horizontal) may include placing one or more heaters (e.g., three mineral insulated conductor heaters) within a conduit. FIG. 5 depicts an embodiment of a portion of three insulated conductor heaters 140 placed within conduit 168. Insulated conductor heaters 140 may be spaced within conduit 168 using spacers 170 to locate the insulated conductor heater within the conduit.

The conduit may be coiled onto a spool. The spool may be placed on a transporting platform such as a truck bed or other platform that can be transported to a site of a wellbore. The conduit may be unreeled from the spool at the wellbore and inserted into the wellbore to install the heater within the wellbore. A welded cap may be placed at an end of the coiled conduit. The welded cap may be placed at an end of the conduit that enters the wellbore first. The conduit may allow easy installation of the heater into the wellbore. The conduit may also provide support for the heater.

Coiled tubing installation may reduce a number of welded and/or threaded connections in a length of casing. Welds and/or threaded connections in coiled tubing may be pre-tested for integrity (e.g., by hydraulic pressure testing). Coiled tubing is available from Quality Tubing, Inc. (Houston, Texas), Precision Tubing (Houston, Texas), and other manufacturers. Coiled tubing may be available in many sizes and different materials. Sizes of coiled tubing may range from about 2.5 cm (1 inch) to about 15 cm (6 inches). Coiled tubing may be available in a variety of different metals, including carbon steel. Coiled tubing may be spooled on a large diameter reel. The reel may be carried on a coiled tubing unit. Suitable coiled tubing units are available from Halliburton (Duncan, Oklahoma), Fleet Cementers, Inc. (Cisco, Texas), and Coiled Tubing Solutions, Inc. (Eastland, Texas). Coiled tubing may be unwound from the reel, passed through a straightener, and inserted into a wellbore. A wellcap may be attached (e.g., welded) to an end of the coiled tubing before inserting the coiled tubing into a well. After insertion, the coiled tubing may be cut from the coiled tubing on the reel.

FIG. 6 illustrates an embodiment of a conductor-in-conduit heater that may heat a hydrocarbon containing formation. Conductor 174 may be disposed in conduit 176. Conductor 174 may be a rod or conduit of electrically conductive material. Low resistance sections 178 may be present at both ends of conductor 174 to generate less heating in these sections. Low resistance section 178 may be formed by having a greater cross-sectional area of conductor 174 in that section, or the sections may be made of material having less resistance. In certain embodiments, low resistance section 178 includes a low resistance conductor coupled to conductor 174. In some heater embodiments, conductors 174 may be 316, 304, or 310 stainless steel rods with diameters of approximately 2.8 cm. In some heater embodiments, conductors are 316, 304, or 310 stainless steel pipes with diameters of approximately 2.5 cm. Larger or smaller diameters of rods or pipes may be used to achieve desired heating of a formation. The diameter and/or wall thickness of conductor 174 may be varied along a length of the conductor to establish different heating rates at various portions of the conductor.

Conduit 176 may be made of an electrically conductive material. For example, conduit 176 may be a 7.6 cm, schedule 40 pipe made of 316, 304, or 310 stainless steel. Conduit 176 may be disposed in opening 114 in hydrocarbon layer 116. Opening 114 has a diameter able to accommodate conduit 176. A diameter of the opening may be from about 10 cm to about 13 cm. Larger or smaller diameter openings may be used to accommodate particular conduits or designs.

Conductor 174 may be centered in conduit 176 by centralizer 180. Centralizer 180 may electrically isolate conductor 174 from conduit 176. Centralizer 180 may inhibit movement and properly locate conductor 174 within conduit 176. Centralizer 180 may be made of a ceramic material or a combination of ceramic and metallic materials. Centralizers 180 may inhibit deformation of conductor 174 in conduit 176. Centralizer 180 may be spaced at intervals between approximately 0.5 m and approximately 3 m along conductor 174.

A second low resistance section 178 of conductor 174 may couple conductor 174 to wellhead 152, as depicted in FIG. 6. Electrical current may be applied to conductor 174 from power cable 184 through low resistance section 178 of conductor 174. Electrical current may pass from conductor 174 through sliding connector 188 to conduit 176. Conduit 176 may be electrically insulated from overburden casing 156 and from wellhead 152 to return electrical current to power cable 184. Heat may be generated in conductor 174 and conduit 176. The generated heat may radiate within conduit 176 and opening 114 to heat at least a portion of hydrocarbon layer 116. As an example, a voltage of about 330 volts and a current of about 795 amps may be supplied to conductor 174 and conduit 176 in a 229 m (750 ft) heated section to generate about 1150 watts/meter of conductor 174 and conduit 176.

Overburden casing 156 may be disposed in overburden 128. Overburden casing 156 may, in some embodiments, be surrounded by materials that inhibit heating of overburden 128. Low resistance section 178 of conductor 174 may be placed in overburden casing 156. Low resistance section 178 of conductor 174 may be made of, for example, carbon steel. Low resistance section 178 may have a diameter between about 2 cm to about 5 cm or, for example, a diameter of about 4 cm. Low resistance section 178 of conductor 174 may be centralized within overburden casing 156 using centralizers 180. Centralizers 180 may be spaced at intervals of approximately 6 m to approximately 12 m or, for example, approximately 9 m along low resistance section 178 of conductor 174. In a heater embodiment, low resistance section 178 of conductor 174 is coupled to conductor 174 by a weld or welds. In other heater embodiments, low resistance sections may be threaded, threaded and welded, or otherwise coupled to the conductor. Low resistance section 178 may generate little and/or no heat in overburden casing 156. Packing material 126 may be placed between overburden casing 156 and opening 114. Packing material 126 may inhibit fluid from flowing from opening 114 to surface 130.

In a heater embodiment, overburden casing 156 is a 7.6 cm schedule 40 carbon steel pipe. In some embodiments, the overburden casing may be cemented in the overburden. Reinforcing material 154 may be slag or silica flour or a mixture thereof (e.g., about 1.58 grams per cubic centimeter slag/silica flour). Reinforcing material 154 may extend radially a width of about 5 cm to about 25 cm. Reinforcing material 154 may also be made of material designed to inhibit flow of heat into overburden 128. In other heater embodiments, overburden casing 156 may not be cemented into the formation. Having an uncemented overburden casing may facilitate removal of conduit 176 if the need for removal should arise.

Surface conductor 166 may couple to wellhead 152. Surface conductor 166 may have a diameter of about 10 cm to about 30 cm or, in certain embodiments, a diameter of about 22 cm. Electrically insulating sealing flanges may mechanically couple low resistance section 178 of conductor 174 to wellhead 152 and to electrically couple low resistance section 178 to power cable 184. The electrically insulating sealing flanges may couple power cable 184 to wellhead 152. For example, power cable 184 may be a copper cable, wire, or other elongated member. Power cable 184 may include any material having a substantially low resistance. The power cable may be clamped to the bottom of the low resistance conductor section to make electrical contact.

In an embodiment, heat may be generated in or by conduit 176. About 10% to about 30%, or, for example, about 20%, of the total heat generated by the heater may be generated in or by conduit 176. Both conductor 174 and conduit 176 may be made of stainless steel. Dimensions of conductor 174 and conduit 176 may be chosen such that the conductor will dissipate heat in a range from approximately 650 watts per meter to 1650 watts per meter. A temperature in conduit 176 may be approximately 480 °C to approximately 815 °C, and a temperature in conductor 174 may be approximately 500 °C to 840 °C. Substantially uniform heating of a hydrocarbon containing formation may be provided along a length of conduit 176 greater than about 300 m or, even greater than about 600 m.

Conduit 186 may be provided to add gas from gas source 160, through valve 162, and into opening 114. An opening is provided in reinforcing material 154 to allow gas to pass into opening 114. Conduit 186 and valve 164 may be used at different times to bleed off pressure and/or control pressure proximate opening 114. It is to be understood that any of the heating sources described herein may also be equipped with conduits to supply additional components, bleed off fluids, and/or to control pressure.

FIG. 7 depicts a cross-sectional representation of an embodiment of a removable conductor-in-conduit heater. Conduit 176 may be placed in opening 114 through overburden 128 such that a gap remains between the conduit and overburden casing 156. Fluids may be removed from opening 114 through the gap between conduit 176 and overburden casing 156. Fluids may be removed from the gap through conduit 186. Conduit 176 and components of the heater included within the conduit that are coupled to wellhead 152 may be removed from opening 114 as a single unit. The heater may be removed as a single unit to be repaired, replaced, and/or used in another portion of the formation.

In certain embodiments, portions of a conductor-in-conduit heater may be moved or removed to adjust a portion of the formation that is heated by the heater. For example, in a horizontal well the conductor-in-conduit heater may be initially almost as long as the opening in the formation. As products are produced from the formation, the conductor-in-conduit heater may be moved so that it is placed at location further from the end of the opening in the formation. Heat may be applied to a different portion of the formation by adjusting the location of the heater. In certain embodiments, an end of the heater may be coupled to a sealing mechanism (e.g., a packing mechanism, or a plugging mechanism) to seal off perforations in a liner or casing. The sealing mechanism may inhibit undesired fluid production from portions of the heater wellbore from which the conductor-in-conduit heater has been removed.

FIG. 8 illustrates an embodiment of a wellhead. Wellhead 152 may be coupled to electrical junction box 190 by flange 192 or any other suitable mechanical device. Electrical junction box 190 may control power (current and voltage) supplied to an electric heater. Power source 194 may be included in electrical junction box 190. In a heater embodiment, the electric heater is a conductor-in-conduit heater. Flange 192 may include stainless steel or any other suitable sealing material. Conductor 196 may electrically couple conduit 176 to power source 194. In some embodiments, power source 194 may be located outside wellhead 152 and the power source is coupled to the wellhead with power cable 184, as shown in FIG. 6. Low resistance section 178 may be coupled to power source 194. Compression seal 198 may seal conductor 196 at an inner surface of electrical junction box 190.

Flange 192 may be sealed with metal o-ring 200. Conduit 202 may couple flange 192 to flange 214. Flange 214 may couple to an overburden casing. Flange 214 may be sealed with o-ring 204 (e.g., metal o-ring or steel o-ring). Low resistance section 178 of the conductor may couple to electrical junction box 190. Low resistance section 178 may be passed through flange 192. Low resistance section 178 may be sealed in flange 192 with o-ring assembly 218. Assemblies 218 are designed to insulate low resistance section 178 from flange 192 and flange 214. Compression seal 198 may be designed to electrically insulate conductor 196 from flange 192 and junction box 190. Centralizer 180 may couple to low resistance section 178. Thermocouples 208 may be coupled to thermocouple flange 220 with connectors 206 and wire 210. Thermocouples 208 may be enclosed in an electrically insulated sheath (e.g., a metal sheath). Thermocouples 208 may be sealed in thermocouple flange 220 with compression seals 212. Thermocouples 208 may be used to monitor temperatures in the heated portion downhole. In some embodiments, fluids (e.g., vapors) may be removed through wellhead 152. For example, fluids from outside conduit 176 may be removed through flange 222 or fluids within the conduit may be removed through flange 224.

FIG. 9 illustrates an embodiment of a conductor-in-conduit heater placed substantially horizontally within hydrocarbon layer 116. Heated section 226 may be placed substantially horizontally within hydrocarbon layer 116. Heater casing 238 may be placed within hydrocarbon layer 116. Heater casing 238 may be formed of a corrosion resistant, relatively rigid material (e.g., 304 stainless steel). Heater casing 238 may be coupled to overburden casing 156. Overburden casing 156 may include materials such as carbon steel. In an embodiment, overburden casing 156 and heater casing 238 have a diameter of about 15 cm. Expansion mechanism 246 may be placed at an end of heater casing 238 to accommodate thermal expansion of the conduit during heating and/or cooling.

To install heater casing 238 substantially horizontally within hydrocarbon layer 116, overburden casing 156 may bend from a vertical direction in overburden 128 into a horizontal direction within hydrocarbon layer 116. A curved wellbore may be formed during drilling of the wellbore in the formation. Heater casing 238 and overburden casing 156 may be installed in the curved wellbore. A radius of curvature of the curved wellbore may be determined by properties of drilling in the overburden and the formation. For example, the radius of curvature may be about 200 m from point 234 to point 248.

Conduit 176 may be placed within heater casing 238. In some embodiments, conduit 176 may be made of a corrosion resistant metal (e.g., 304 stainless steel). Conduit 176 may be heated to a high temperature. Conduit 176 may also be exposed to hot formation fluids. Conduit 176 may be treated to have a high emissivity. Conduit 176 may have upper section 230. In some embodiments, upper section 230 may be made of a less corrosion resistant metal than other portions of conduit 176 (e.g., carbon steel). A large portion of upper section 230 may be positioned in overburden 128 of the formation. Upper section 230 may not be exposed to temperatures as high as the temperatures of conduit 176. In an embodiment, conduit 176 and upper section 230 have a diameter of about 7.6 cm.

Conductor 174 may be placed in conduit 176. A portion of the conduit placed adjacent to conductor 174 may be made of a metal that has desired electrical properties, emissivity, creep resistance, and corrosion resistance at high temperatures. Conductor 174 may include, but is not limited to, 310 stainless steel, 304 stainless steel, 316 stainless steel, 347 stainless steel, and/or other steel or non-steel alloys. Conductor 174 may have a diameter of about 3 cm, however, a diameter of conductor 174 may vary depending on, but not limited to, heating requirements and power requirements. Conductor 174 may be located in conduit 176 using one or more centralizers 180. Centralizers 180 may be ceramic or a combination of metal and ceramic. Centralizers 180 may inhibit conductor 174 from contacting conduit 176. In some embodiments, centralizers 180 may be coupled to conductor 174. In other embodiments, centralizers 180 may be coupled to conduit 176. Conductor 174 may be electrically coupled to conduit 176 using sliding connector 188.

Conductor 174 may be coupled to transition conductor 236. Transition conductor 236 may be used as an electrical transition between lead-in conductor 232 and conductor 174. In an embodiment, transition conductor 236 may be carbon steel. Transition conductor 236 may be coupled to lead-in conductor 232 with electrical connector 242. FIG. 10 illustrates an enlarged view of an embodiment of a junction of transition conductor 236, electrical connector 242, insulator 240, and lead-in conductor 232. Lead-in conductor 232 may include one or more conductors (e.g., three conductors). In certain embodiments, the one or more conductors may be insulated copper conductors (e.g., rubber-insulated copper cable). In some embodiments, the one or more conductors may be insulated or un-insulated stranded copper cable. As shown in FIG. 10, insulator 240 may be placed inside lead-in conductor 232. Insulator 240 may include electrically insulating materials such as fiberglass. Insulator 240 may couple electrical connector 242 to heater support 228, as shown in FIG. 9. In an embodiment, electrical current may flow from a power supply through lead-in conductor 232, through transition conductor 236, into conductor 174, and return through conduit 176 and upper section 230.

Referring to FIG. 9, heater support 228 may include a support that is used to install heated section 226 in hydrocarbon layer 116. For example, heater support 228 may be a sucker rod that is inserted through overburden 128 from a ground surface. The sucker rod may include one or more portions that can be coupled to each other at the surface as the rod is inserted into the formation. In some embodiments, heater support 228 is a single piece assembled in an assembly facility. Inserting heater support 228 into the formation may push heated section 226 into the formation.

Overburden casing 156 may be supported within overburden 128 using reinforcing material 154. Reinforcing material may include cement (e.g., Portland cement). Surface conductor 166 may enclose reinforcing material 154 and overburden casing 156 in a portion of overburden 128 proximate the ground surface. Surface conductor 166 may include a surface casing.

FIG. 11 illustrates a schematic of an alternative embodiment of a conductor-in-conduit heater placed substantially horizontally within a formation. In an embodiment, heater support 228 may be a low resistance conductor (e.g., low resistance section 178 as shown in FIG. 6). Heater support 228 may include carbon steel or other electrically conducting materials. Heater support 228 may be electrically coupled to transition conductor 236 and conductor 174.

In some embodiments, a heater may be placed within an uncased wellbore in a hydrocarbon containing formation. FIG. 12 illustrates a schematic of an embodiment of a conductor-in-conduit heater placed substantially horizontally within an uncased wellbore in a formation. Heated section 226 may be placed within opening 114 in hydrocarbon layer 116. In certain embodiments, heater support 228 may be a low resistance conductor (e.g., low resistance section 178 as shown in FIG. 6). Heater support 228 may be electrically coupled to transition conductor 236 and conductor 174. FIG. 13 depicts an alternative embodiment of the conductor-in-conduit heater shown in FIG. 12. In certain embodiments, perforated casing 250 may be placed in opening 114 as shown in FIG. 13. In some embodiments, centralizers 180 may be used to support perforated casing 250 within opening 114.

In other heater embodiments, heated section 226, as shown in FIGS. 9, 11, and 12, may be placed in a wellbore with an orientation other than substantially horizontally in hydrocarbon layer 116. For example, heated section 226 may be placed in hydrocarbon layer 116 at an angle of about 45° or substantially vertically in the formation. In addition, elements of the heater placed in overburden 128 (e.g., heater support 228, overburden casing 156, upper section 230, etc.) may have an orientation other than substantially vertical within the overburden.

In certain heater embodiments, a heater may be removably installed in a formation. Heater support 228 may be used to install and/or remove the heater, including heated section 226, from the formation. The heater may be removed to repair, replace, and/or use the heater in a different wellbore. The heater may be reused in the same formation or in a different formation. In some embodiments, a heater or a portion of a heater may be spooled on a coiled tubing rig and moved to another well location.

In some embodiments for heating a hydrocarbon containing formation, more than one heater may be installed in a wellbore or heater well. Having more than one heater in a wellbore may provide the ability to heat a selected portion or portions of a formation at a different rate than other portions of the formation. Having more than one heater in a wellbore may provide a backup heater in the wellbore or heater should one or more of the heaters fail. Having more than one heater may allow a uniform temperature profile to be established along a desired portion of the wellbore. Having more than one heater may allow for rapid heating of a hydrocarbon layer or layers to a pyrolysis temperature from ambient temperature. The more than one heater may include similar types of heaters or may include different types of heaters. For example, the more than one heater may be a natural distributed combustor heater, an insulated conductor heater, a conductor-in-conduit heater, an elongated member heater, a downhole combustor (e.g., a downhole flameless combustor or a downhole combustor), etc.

FIG. 14 depicts a representation of an embodiment of centralizer 180 disposed on conductor 174. Discs 258 may maintain positions of centralizer 180 relative to conductor 174. Discs 258 may be metal discs welded to conductor 174. Discs 258 may be tack-welded to conductor 174. FIG. 15 depicts a top view representation of a centralizer embodiment. Centralizer 180 may be made of any suitable electrically insulating material able to withstand high voltage at high temperatures. Examples of such materials include, but are not limited to, aluminum oxide and/or Macor. Centralizer 180 may electrically insulate conductor 174 from conduit 176, as shown in FIGS. 14 and 15.

Heat may be generated by the conductor-in-conduit heater within an open wellbore. Generated heat may radiatively heat a portion of a hydrocarbon containing formation adjacent to the conductor-in-conduit heater. To a lesser extent, gas conduction adjacent to the conductor-in-conduit heater may heat a portion of the formation. Using an open wellbore completion may reduce casing and packing costs associated with filling the opening with a material to provide conductive heat transfer between the insulated conductor and the formation. In addition, heat transfer by radiation may be more efficient than heat transfer by conduction in a formation, so the heaters may be operated at lower temperatures using radiative heat transfer. Operating at a lower temperature may extend the life of the heater and/or reduce the cost of material needed to form the heater.

The conductor-in-conduit heater may be installed in opening 114. In an embodiment, the conductor-in-conduit heater may be installed into a well by sections. For example, a first section of the conductor-in-conduit heater may be suspended in a wellbore by a rig. The section may be about 12 m in length. A second section (e.g., of substantially similar length) may be coupled to the first section in the well. The second section may be coupled by welding the second section to the first section and/or with threads disposed on the first and second section. An orbital welder disposed at the wellhead may weld the second section to the first section. The first section may be lowered into the wellbore by the rig. This process may be repeated with subsequent sections coupled to previous sections until a heater of desired length is placed in the wellbore. In some embodiments, three sections may be welded together prior to being placed in the wellbore. The welds may be formed and tested before the rig is used to attach the three sections to a string already placed in the ground. The three sections may be lifted by a crane to the rig. Having three sections already welded together may reduce installation time of the heater.

Assembling a heater at a location proximate a formation (e.g., at the site of a formation) may be more economical than shipping a pre-formed heater and/or conduits to the hydrocarbon formation. For example, assembling the heater at the site of the formation may reduce costs for transporting assembled heaters over long distances. In addition, heaters may be more easily assembled in varying lengths and/or of varying materials to meet specific formation requirements at the formation site. For example, a portion of a heater that is to be heated may be made of a material (e.g., 304 stainless steel or other high temperature alloy) while a portion of the heater in the overburden may be made of carbon steel. Forming the heater at the site may allow the heater to be specifically made for an opening in the formation so that the portion of the heater in the overburden is carbon steel and not a more expensive, heat resistant alloy. Heater lengths may vary due to varying formation layer depths and formation properties. For example, a formation may have a varying thickness and/or may be located underneath rolling terrain, uneven surfaces, and/or an overburden with a varying thickness. Heaters of varying length and of varying materials may be assembled on site in lengths determined by the depth of each opening in the formation.

FIG. 16 depicts an embodiment for assembling a conductor-in-conduit heater and installing the heater in a formation. The conductor-in-conduit heater may be assembled in assembly facility 272. In some embodiments, the heater is assembled from conduits shipped to the formation site. In other embodiments, heaters may be made from plate stock that is formed into conduits at the assembly facility. An advantage of forming a conduit at the assembly facility may be that a surface of plate stock may be treated with a desired coating (e.g., a coating that allows the emissivity to approach one) or cladding (e.g., copper cladding) before forming the conduit so that the treated surface is an inside surface of the conduit. In some embodiments, portions of heaters may be formed from plate stock at the assembly facility, while other portions of the heater may be formed from conduits shipped to the formation site.

Individual conductor-in-conduit heater 274 may include conductor 174 and conduit 176 as shown in FIG. 17. In an embodiment, conductor 174 and conduit 176 heaters may be made of a number of joined together sections. In an embodiment, each section is a standard 40 ft (12.2 m) section of pipe. Other section lengths may also be formed and/or utilized. In addition, sections of conductor 174 and/or conduit 176 may be treated in assembly facility 272 before, during, or after assembly. The sections may be treated, for example, to increase an emissivity of the sections by roughening and/or oxidation of the sections.

Each conductor-in-conduit heater 274 may be assembled in an assembly facility. Components of conductor-in-conduit heater 274 may be placed on or within individual conductor-in-conduit heater 274 in the assembly facility. Components may include, but are not limited to, one or more centralizers, low resistance sections, sliding connectors, insulation layers, and coatings, claddings, or coupling materials.

As shown in FIG. 16, each individual conductor-in-conduit heater 274 may be coupled to at least one individual conductor-in-conduit heater 274 at coupling station 278 to form conductor-in-conduit heater of desired length 276. The desired length may be, for example, a length of a conductor-in-conduit heater specified for a selected opening in a formation. In certain embodiments, coupling individual conductor-in-conduit heater 274 to at least one additional individual conductor-in-conduit heater 274 includes welding the individual conductor-in-conduit heater to at least one additional individual conductor-in-conduit heater. In one embodiment, welding each individual conductor-in-conduit heater 274 to an additional individual conductor-in-conduit heater is accomplished by forge welding two adjacent sections together.

In some embodiments, sections of welded together conductor-in-conduit heater of desired length 276 are placed on a bench, holding tray or in an opening in the ground until the entire length of the heater is completed. Weld integrity may be tested as each weld is formed. For example, weld integrity may be tested by a non-destructive testing method such as x-ray testing, acoustic testing, and/or electromagnetic testing. After an entire length of conductor-in-conduit heater of desired length 276 is completed, the conductor-in-conduit heater of desired length may be coiled onto spool 282 in a direction of arrow 284. Coiling conductor-in-conduit heater of desired length 276 may make the heater easier to transport to an opening in a formation. For example, conductor-in-conduit heater of desired length 276 may be more easily transported by truck or train to an opening in the formation.

In some embodiments, a set length of welded together conductor-in-conduit may be coiled onto spool 282 while other sections are being formed at coupling station 278. In some embodiments, the assembly facility may be a mobile facility (e.g., placed on one or more train cars or semi-trailers) that can be moved to an opening in a formation. After forming a welded together length of conductor-in-conduit with components (e.g., centralizers, coatings, claddings, sliding connectors), the conductor-in-conduit length may be lowered into the opening in the formation.

In certain embodiments, conductor-in-conduit heater of desired length 276 may be tested at testing station 280 before coiling the heater. Testing station 280 may be used to test a completed conductor-in-conduit heater of desired length 276 or sections of the conductor-in-conduit heater of desired length. Testing station 280 may be used to test selected properties of conductor-in-conduit heater of desired length 276. For example, testing station 280 may be used to test properties such as, but not limited to, electrical conductivity, weld integrity, thermal conductivity, emissivity, and mechanical strength. In one embodiment, testing station 280 is used to test weld integrity with an Electro-Magnetic Acoustic Transmission (EMAT) weld inspection technique.

Conductor-in-conduit heater of desired length 276 may be coiled onto spool 282 for transporting from assembly facility 272 to an opening in a formation and installation into the opening. In an embodiment, assembly facility 272 is located at a site of the formation. For example, assembly facility 272 may be part of a surface facility used to treat fluids from the formation or located proximate to the formation (e.g., less than about 10 km from the formation or, in some embodiments, less than about 20 km or less than about 30 km). Other types of heaters (e.g., insulated conductor heaters, natural distributed combustor heaters, etc.) may also be assembled in assembly facility 272. These other heaters may also be spooled onto spool 282, transported to an opening in a formation, and installed into the opening as is described for conductor-in-conduit heater of desired length 276. In some embodiments, spool 282 may be included as a portion of a coiled tubing rig (e.g., for an insulated conductor heater or a conductor-in-conduit heater).

Transportation of conductor-in-conduit heater of desired length 276 to an opening in a formation is represented by arrow 286 in FIG. 16. Transporting conductor-in-conduit heater of desired length 276 may include transporting the heater on a bed, trailer, a cart of a truck or train, or a coiled tubing unit. In some embodiments, more than one heater may be placed on the bed. Each heater may be installed in a separate opening in the formation. In one embodiment, a train system (e.g., rail system) may be set up to transport heaters from assembly facility 272 to each of the openings in the formation. In some instances, a lift and move track system may be used in which train tracks are lifted and moved to another location after use in one location.

After spool 282 with conductor-in-conduit heater of desired length 276 has been transported to opening 114, the heater may be uncoiled and installed into the opening in a direction of arrow 288. Conductor-in-conduit heater of desired length 276 may be uncoiled from spool 282 while the spool remains on the bed of a truck or train. In some embodiments, more than one conductor-in-conduit heater of desired length 276 may be installed at one time. In one embodiment, more than one heater may be installed into one opening 114. Spool 282 may be re-used for additional heaters after installation of conductor-in-conduit heater of desired length 276. In some embodiments, spool 282 may be used to removed conductor-in-conduit heater of desired length 276 from the opening. Conductor-in-conduit heater of desired length 276 may be re-coiled onto spool 282 as the heater is removed from opening 114. Subsequently, conductor-in-conduit heater of desired length 276 may be re-installed from spool 282 into opening 114 or transported to an alternative opening in the formation and installed the alternative opening.

In certain embodiments, conductor-in-conduit heater of desired length 276, or any heater (e.g., an insulated conductor heater or natural distributed combustor heater), may be installed such that the heater is removable from opening 114. The heater may be removable so that the heater can be repaired or replaced if the heater fails or breaks. In other instances, the heater may be removed from the opening and transported and redeployed in another opening in the formation (or in a different formation) at a later time. In yet other instances, the heater may be removed and replaced with a lower cost heater at later times of heating a formation. Being able to remove, replace, and/or redeploy a heater may be economically favorable for reducing equipment and/or operating costs. In addition, being able to remove and replace an ineffective heater may eliminate the need to form wellbores in close proximity to existing wellbores that have failed heaters in a heated or heating formation.

In some embodiments, a conduit of a desired length may be placed into opening 114 before a conductor of the desired length. The conductor and the conduit of the desired length may be assembled in assembly facility 272. The conduit of the desired length may be installed into opening 114. After installation of the conduit of the desired length, the conductor of the desired length may be installed into opening 114. In an embodiment, the conduit and the conductor of the desired length are coiled onto a spool in assembly facility 272 and uncoiled from the spool for installation into opening 114. Components (e.g., centralizers, sliding connectors, etc.) may be placed on the conductor or conduit as the conductor is installed into the conduit and opening 114.

In certain embodiments, centralizer 180 may include at least two portions coupled together to form the centralizer (e.g., "clam shell" centralizers). In one embodiment, the portions are placed on a conductor and coupled together as the conductor is installed into a conduit or opening. The portions may be coupled with fastening devices such as, but not limited to, clamps, bolts, screws, snap-locks, and/or adhesive. The portions may be shaped such that a first portion fits into a second portion. For example, an end of the first portion may have a slightly smaller width than an end of the second portion so that the ends overlap when the two portions are coupled.

In some embodiments, a low resistance section is coupled to conductor-in-conduit heater of desired length 276 in assembly facility 272. In other embodiments, a low resistance section is coupled to conductor-in-conduit heater of desired length 276 after the heater is installed into opening 114. A low resistance section of a desired length may be assembled in assembly facility 272. An assembled low resistance conductor may be coiled onto a spool. The assembled low resistance conductor may be uncoiled from the spool and coupled to conductor-in-conduit heater of desired length 276 after the heater is installed in opening 114. In another embodiment, a low resistance section is assembled as the low resistance conductor is coupled to conductor-in-conduit heater of desired length 276 and installed into opening 114. Conductor-in-conduit heater of desired length 276 may be coupled to a support after installation so that a low resistance section is coupled to the installed heater.

Assembling a desired length of a low resistance conductor may include coupling individual low resistance conductors together. The individual low resistance conductors may be plate stock conductors obtained from a manufacturer. The individual low resistance conductors may be coupled to an electrically conductive material to lower the electrical resistance of the low resistance conductor. The electrically conductive material may be coupled to the individual low resistance conductor before assembly of the desired length of low resistance conductor. In one embodiment, the individual low resistance conductors may have threaded ends that are coupled together. In another embodiment, the individual low resistance conductors may have ends that are welded together. Ends of the individual low resistance conductors may be shaped such that an end of a first individual low resistance conductor fits into an end of a second individual low resistance conductor. For example, an end of a first individual low resistance conductor may be a female-shaped end while an end of a second individual low resistance conductor is a male-shaped end.

In another embodiment, a conductor-in-conduit heater of a desired length may be assembled at a wellbore (or opening) in a formation and installed into the wellbore as the conductor-in-conduit heater is assembled. Individual conductors may be coupled to form a first section of a conductor of desired length. Similarly, conduits may be coupled to form a first section of a conduit of desired length. The first formed sections of the conductor and the conduit may be installed into the wellbore. The first formed sections of the conductor and the conduit may be electrically coupled at a first end that is installed into the wellbore. The first sections of the conductor and conduit may, in some embodiments, be coupled substantially simultaneously. Additional sections of the conductor and/or conduit may be formed during or after installation of the first formed sections. The additional sections of the conductor and/or conduit may be coupled to the first formed sections of the conductor and/or conduit and installed into the wellbore. Centralizers and/or other components may be coupled to sections of the conductor and/or conduit and installed with the conductor and the conduit into the wellbore.

In an embodiment, an elongated member may be disposed within an opening (e.g., an open wellbore) in a hydrocarbon containing formation. The opening may be an uncased opening in the hydrocarbon containing formation. The elongated member may be a length (e.g., a strip) of metal or any other elongated piece of metal (e.g., a rod). The elongated member may include stainless steel. The elongated member may be made of a material able to withstand corrosion at high temperatures within the opening.

An elongated member may be a bare metal heater. "Bare metal" refers to a metal that does 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 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 includes metal 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.

An elongated member may have a length of about 650 m. Longer lengths may be achieved using sections of high strength alloys, but such elongated members may be expensive. In some embodiments, an elongated member may be supported by a plate in a wellhead. The elongated member may include sections of different conductive materials that are welded together end-to-end. A large amount of electrically conductive weld material may be used to couple the separate sections together to increase strength of the resulting member and to provide a path for electricity to flow that will not result in arcing and/or corrosion at the welded connections. In some embodiments, different sections may be forge welded together. The different conductive materials may include alloys with a high creep resistance. The sections of different conductive materials may have varying diameters to ensure uniform heating along the elongated member. A first metal that has a higher creep resistance than a second metal typically has a higher resistivity than the second metal. The difference in resistivities may allow a section of larger cross-sectional area, more creep resistant first metal to dissipate the same amount of heat as a section of smaller cross-sectional area second metal. The cross-sectional areas of the two different metals may be tailored to result in substantially the same amount of heat dissipation in two welded together sections of the metals. The conductive materials may include, but are not limited to, 617 Inconel, HR-120, 316 stainless steel, and 304 stainless steel. For example, an elongated member may have a 60 meter section of 617 Inconel, 60 meter section of HR-120, and 150 meter section of 304 stainless steel. In addition, the elongated member may have a low resistance section that may run from the wellhead through the overburden. This low resistance section may decrease the heating within the formation from the wellhead through the overburden. The low resistance section may be the result of, for example, choosing a electrically conductive material and/or increasing the cross-sectional area available for electrical conduction.

In a heater embodiment, a support member may extend through the overburden, and the bare metal elongated member or members may be coupled to the support member. A plate, a centralizer, or other type of support member may be located near an interface between the overburden and the hydrocarbon layer. A low resistivity cable, such as a stranded copper cable, may extend along the support member and may be coupled to the elongated member or members. The low resistivity cable may be coupled to a power source that supplies electricity to the elongated member or members.

FIG. 18 illustrates an embodiment of a plurality of elongated members that may heat a hydrocarbon containing formation. Two or more (e.g., four) elongated members 300 may be supported by support member 304. Elongated members 300 may be coupled to support member 304 using insulated centralizers 302. Support member 304 may be a tube or conduit. Support member 304 may also be a perforated tube. Support member 304 may provide a flow of an oxidizing fluid into opening 114. Support member 304, elongated members 300, and insulated centralizers 302 may be disposed in opening 114 in hydrocarbon layer 116. Insulated centralizers 302 may maintain a location of elongated members 300 on support member 304 such that lateral movement of elongated members 300 is inhibited at temperatures high enough to deform support member 304 or elongated members 300. Elongated members 300, in some embodiments, may be metal strips of about 2.5 cm wide and about 0.3 cm thick stainless steel. Electrical current may be applied to elongated members 300 such that elongated members 300 may generate heat due to electrical resistance.

Elongated members 300 may be electrically coupled in series. Electrical current may be supplied to elongated members 300 using lead-in conductor 150. Lead-in conductor 150 may be coupled to wellhead 152. Electrical current may be returned to wellhead 152 using lead-out conductor 308 coupled to elongated members 300. Lead-in conductor 150 and lead-out conductor 308 may be coupled to wellhead 152 at surface 130 through a sealing flange located between wellhead 152 and overburden 128. The sealing flange may inhibit fluid from escaping from opening 114 to surface 130 and/or atmosphere. Lead-in conductor 150 and lead-out conductor 308 may be coupled to elongated members 300 using a cold pin transition conductor. Lead-in conductor 150 and lead-out conductor 308 may be made of low resistance conductors so that substantially no heat is generated from electrical current passing through lead-in conductor 150 and lead-out conductor 308.

In some embodiments, overburden casing 156 may be placed in reinforcing material 154 in overburden 128. In other embodiments, overburden casing may not be cemented to the formation. Surface conductor 166 may be disposed in reinforcing material 154. Support member 304 may be coupled to wellhead 152 at surface 130. Centralizer 180 may maintain a location of support member 304 within overburden casing 156. Electrical current may be supplied to elongated members 300 to generate heat. Heat generated from elongated members 300 may radiate within opening 114 to heat at least a portion of hydrocarbon layer 116.

Oxidizing fluid may be provided along a length of elongated members 300 from oxidizing fluid source 120. The oxidizing fluid may inhibit carbon deposition on or proximate the elongated members. For example, the oxidizing fluid may react with hydrocarbons to form carbon dioxide. The carbon dioxide may be removed from the opening. Openings 306 in support member 304 may provide a flow of the oxidizing fluid along the length of elongated members 300. Openings 306 may be critical flow orifices. In some embodiments, a conduit may be disposed proximate elongated members 300 to control the pressure in the formation and/or to introduce an oxidizing fluid into opening 114. Without a flow of oxidizing fluid, carbon deposition may occur on or proximate elongated members 300 or on insulated centralizers 302. Carbon deposition may cause shorting between elongated members 300 and insulated centralizers 302 or hot spots along elongated members 300. The oxidizing fluid may be used to react with the carbon in the formation. The heat generated by reaction with the carbon may complement or supplement electrically generated heat.

Subsurface pressure in a hydrocarbon containing formation may correspond to the fluid pressure generated within the formation. Heating hydrocarbons within a hydrocarbon containing formation may generate fluids by pyrolysis. The generated fluids may be vaporized within the formation. Vaporization and pyrolysis reactions may increase the pressure within the formation. Fluids that contribute to the increase in pressure may include, but are not limited to, fluids produced during pyrolysis and water vaporized during heating. As temperature within a selected section of a heated portion of the formation increases, a pressure within the selected section may increase as a result of increased fluid generation and vaporization of water. Controlling a rate of fluid removal from the formation may allow for control of pressure in the formation.

In some embodiments, pressure within a selected section of a heated portion of a hydrocarbon containing formation may vary depending on factors such as depth, distance from a heat source, a richness of the hydrocarbons within the hydrocarbon containing formation, and/or a distance from a producer well. Pressure within a formation may be determined at a number of different locations (e.g., near or at production wells, near or at heat sources, or at monitor wells).

Heating of a hydrocarbon containing formation to a pyrolysis temperature range may occur before substantial permeability has been generated within the hydrocarbon containing formation. An initial lack of permeability may inhibit the transport of generated fluids from a pyrolysis zone within the formation to a production well. As heat is initially transferred from a heat source to a hydrocarbon containing formation, a fluid pressure within the hydrocarbon containing formation may increase proximate a heat source. Such an increase in fluid pressure may be caused by generation of fluids during pyrolysis of at least some hydrocarbons in the formation. The increased fluid pressure may be released, monitored, altered, and/or controlled through the heat source. For example, the heat source may include a valve that allows for removal of some fluid from the formation. In some heater embodiments, the heater may include an open wellbore configuration that inhibits pressure damage to the heater.

In an in situ conversion process embodiment, pressure may be increased within a selected section of a portion of a hydrocarbon containing formation to a selected pressure during pyrolysis. A selected pressure may be within a range from about 2 bars absolute to about 72 bars absolute or, in some embodiments, 2 bars absolute to 36 bars absolute. Alternatively, a selected pressure may be within a range from about 2 bars absolute to about 18 bars absolute. In some in situ conversion process embodiments, a majority of hydrocarbon fluids may be produced from a formation having a pressure within a range from about 2 bars absolute to about 18 bars absolute. The pressure during pyrolysis may vary or be varied. The pressure may be varied to alter and/or control a composition of a formation fluid produced, to control a percentage of condensable fluid as compared to non-condensable fluid, and/or to control an API gravity of 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.

In some in situ conversion process embodiments, increased pressure due to fluid generation may be maintained within the heated portion of the formation. Maintaining increased pressure within a formation may inhibit formation subsidence during in situ conversion. Increased formation pressure may promote generation of high quality products during pyrolysis. Increased formation 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. Increased formation pressure may reduce or eliminate the need to compress formation fluids at the surface to transport the fluids in collection conduits to surface facilities. Maintaining increased pressure within a formation may also facilitate generation of electricity from produced non-condensable fluid. For example, the produced non-condensable fluid may be passed through a turbine to generate electricity.

Increased pressure in the formation may also be maintained to produce more and/or improved formation fluids. In certain in situ conversion process embodiments, significant amounts (e.g., a majority) of the hydrocarbon fluids produced from a formation may be non-condensable hydrocarbons. Pressure may be selectively increased and/or maintained within the formation to promote formation of smaller chain hydrocarbons in the formation. Producing small chain hydrocarbons in the formation may allow more non-condensable hydrocarbons to be produced from the formation. The condensable hydrocarbons produced from the formation at higher pressure may be of a higher quality (e.g., higher API gravity) than condensable hydrocarbons produced from the formation at a lower pressure.

A high pressure may be maintained within a heated portion of a hydrocarbon containing formation to inhibit production of formation fluids having carbon numbers greater than, for example, about 25. Some high carbon number compounds may be entrained in vapor in the formation and may be removed from the formation with the vapor. A high pressure in the formation may inhibit entrainment of high carbon number compounds and/or multi-ring hydrocarbon compounds in the vapor. Increasing pressure within the hydrocarbon containing formation may increase a boiling point of a fluid within the portion. 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.

Maintaining increased pressure within a heated portion of the formation may surprisingly allow for production of large quantities of hydrocarbons of increased quality. Maintaining increased pressure may promote vapor phase transport of pyrolyzation fluids within the formation. Increasing the pressure often permits production of lower molecular weight hydrocarbons since such lower molecular weight hydrocarbons will more readily transport in the vapor phase in the formation.

Generation of lower molecular weight hydrocarbons (and corresponding increased vapor phase transport) is believed to be due, in part, to autogenous generation and reaction of hydrogen within a portion of the hydrocarbon containing formation. For example, maintaining an increased pressure may force hydrogen generated during pyrolysis into a liquid phase (e.g., by dissolving). Heating the portion to a temperature within a pyrolysis temperature range may pyrolyze hydrocarbons within the formation to generate pyrolyzation fluids in a liquid phase. The generated components may include double bonds and/or radicals. 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, hydrogen 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. Shorter chain hydrocarbons may enter the vapor phase and may be produced from the formation.

Operating an in situ conversion process at increased pressure may allow for vapor phase production of formation fluid from the formation. Vapor phase production may permit increased recovery of lighter (and relatively high quality) pyrolyzation fluids. Vapor phase production may result in less formation fluid being left in the formation after the fluid is produced by pyrolysis. Vapor phase production may allow for fewer production wells in the formation than are present using liquid phase or liquid/vapor phase production. Fewer production wells may significantly reduce equipment costs associated with an in situ conversion process.

In an embodiment, a portion of a hydrocarbon containing formation may be heated to increase a partial pressure of H_2. In some embodiments, an increased H_2 partial pressure may include H_2 partial pressures in a range from about 0.5 bars to about 7 bars. Alternatively, an increased H_2 partial pressure range may include H_2 partial pressures in a range from about 5 bars to about 7 bars. For example, a majority of hydrocarbon fluids may be produced wherein a H_2 partial pressure is within a range of about 5 bars to about 7 bars. A range of H_2 partial pressures within the pyrolysis H_2 partial pressure range may vary depending on, for example, temperature and pressure of the heated portion of the formation.

Maintaining a H_2 partial pressure within the formation of greater than atmospheric pressure may increase an API value of produced condensable hydrocarbon fluids. Maintaining an increased H_2 partial pressure may increase an API value of produced condensable hydrocarbon fluids to greater than about 25° or, in some instances, greater than about 30°. Maintaining an increased H_2 partial pressure within a heated portion of a hydrocarbon containing formation may increase a concentration of H_2 within the heated portion. The H_2 may be available to react with pyrolyzed components of the hydrocarbons. Reaction of H_2 with the pyrolyzed components of hydrocarbons may reduce polymerization of olefins into tars and other cross-linked, difficult to upgrade, products. Therefore, production of hydrocarbon fluids having low API gravity values may be inhibited.

Controlling pressure and temperature within a hydrocarbon containing formation may allow properties of the produced formation fluids to be controlled. For example, composition and quality of formation fluids produced from the formation may be altered by altering an average pressure and/or an average temperature in a selected section of a heated portion of the formation. The quality of the produced fluids may be evaluated based on characteristics of the fluid such as, but not limited to, API gravity, percent olefins in the produced formation fluids, ethene to ethane ratio, atomic hydrogen to carbon ratio, percent of hydrocarbons within produced formation fluids having carbon numbers greater than 25, total equivalent production (gas and liquid), total liquids production, and/or liquid yield as a percent of Fischer Assay.

Further modifications and alternative embodiments of various aspects of the invention may be apparent to those skilled in the art in view of this description. Accordingly, this description is to be construed as illustrative only and is for the purpose of teaching those skilled in the art the general manner of carrying out the invention. It is to be understood that the forms of the invention shown and described herein are to be taken as the presently preferred embodiments. Elements and materials may be substituted for those illustrated and described herein, parts and processes may be reversed, and certain features of the invention may be utilized independently, all as would be apparent to one skilled in the art after having the benefit of this description of the invention. Changes may be made in the elements described herein without departing from the spirit and scope of the invention as described in the following claims. In addition, it is to be understood that features described herein independently may, in certain embodiments, be combined.

WHAT IS CLAIMED IS:

1. A system configured to heat at least a part of a hydrocarbon containing formation, comprising:

a heater configured to be placed in an opening in the formation;

wherein the system is configured to allow heat to transfer from the heater to a part of the formation to pyrolyze at least some hydrocarbons in the formation; and

wherein the system is configured such that the heater can be removed from the opening in the formation and redeployed in at least one alternative opening in the formation.

2. The system of claim 1, wherein the heater comprises an insulated conductor heater, a conductor-in-conduit heater, a natural distributed combustor heater, and/or a flameless distributed combustor heater.

3. The system of any of claims 1 or 2, wherein the opening in the formation comprises an open or uncased wellbore.

4. The system of any of claims 1-3, wherein the heater is configured to be installed and/or removed using a spool or coiled tubing installation/removal.

5. The system of any of claims 1-4, wherein the opening comprises a diameter of at least approximately 5 cm, or at least approximately 7 cm, or at least approximately 10 cm, and wherein the system is configured to fit in the opening.

6. The system of any of claims 1-5, wherein the heater is configured to be removed from the opening to repair the heater or replace the heater with another heater.

7. A method for installing the system of any of claims 1-6 in a hydrocarbon containing formation, comprising:

placing at least a portion of the system in an opening in a hydrocarbon containing formation by uncoiling at least a portion of the system from a coil and then placing at least a portion of the uncoiled system in the opening.

8. The method of claim 7, further comprising coupling at least one low resistance conductor to the heater, wherein at least one low resistance conductor is configured to be placed in an overburden of the formation.

9. The method of any of claims 7 or 8, further comprising assembling at least a portion of the system at a location near or proximate to the hydrocarbon containing formation.

10. The method of any of claims 7-9, further comprising coiling at least a portion of the system.

11. The method of any of claims 7-10, further comprising removing at least a portion of the system from the opening by recoiling at least a portion of the system.

12. The method of any of claims 7-11, further comprising coiling and/or uncoiling the heater on a spool.

13. The method of any of claims 7-12, further comprising transporting the heater on a cart or train from an assembly location to the opening in the hydrocarbon containing formation.

14. The method of claim 13, wherein the cart or train can be further used to transport more than one heater to more than one opening in the hydrocarbon containing formation.

15. The method of any of claims 7-14, further comprising removing the heater from the opening in the formation to inspect and/or repair the heater and reinstall the heater in the opening, to redeploy the heater in at least one alternative opening in the formation, or to replace at least a portion of the heater.

16. A method of treating at least a part of a hydrocarbon containing formation in situ using the system of any of claims 1-6, comprising:

providing heat from one or more heaters placed within one or more openings in the formation to at least one part of the formation;

allowing the heat to transfer from the one or more heaters to a part of the formation; and

producing a mixture from the formation.

17. The method of claim 16, further comprising maintaining a temperature within at least a portion of the formation within a pyrolysis temperature range with a lower pyrolysis temperature of about 250 °C and an upper pyrolysis temperature of about 400 °C.

18. The method of any of claims 16-17, further comprising heating at least a part of the formation to substantially pyrolyze at least some of the hydrocarbons within the formation.

19. The method of any of claims 16-18, further comprising controlling a pressure and a temperature within at least a majority of the part of the formation, wherein the pressure is controlled as a function of temperature, or the temperature is controlled as a function of pressure.

20. The method of any of claims 16-19, wherein allowing the heat to transfer from the one or more heaters to the part of the formation comprises transferring heat substantially by conduction.

21. The method of any of claims 16-20, wherein the produced mixture comprises condensable hydrocarbons having an API gravity of at least about 25°.

22. The method of any of claims 16-21, further comprising controlling a pressure within at least a majority of a part of the formation, wherein the controlled pressure is at least about 2.0 bars absolute.

23. The method of any of claims 16-22, further comprising controlling formation conditions such that the produced mixture comprises a partial pressure of H_2 within the mixture greater than about 0.5 bars.

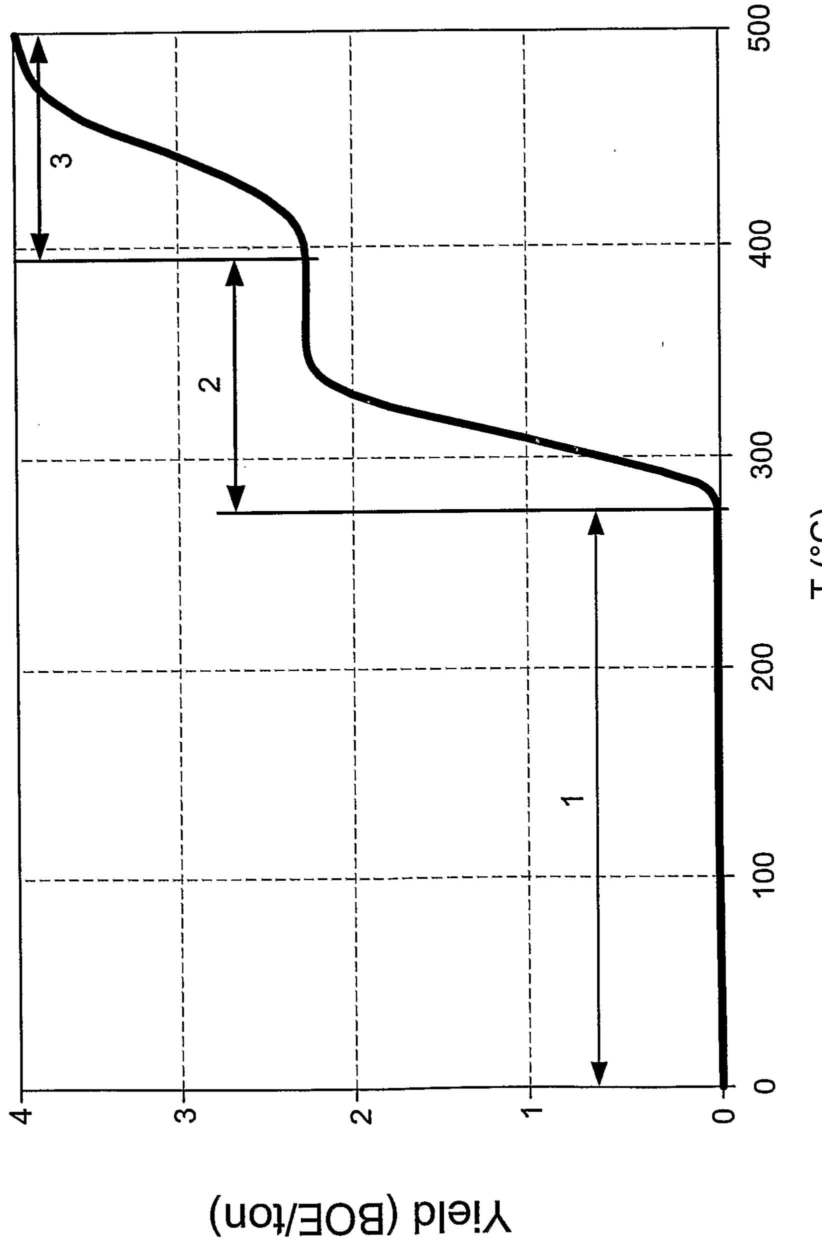

FIG. 1

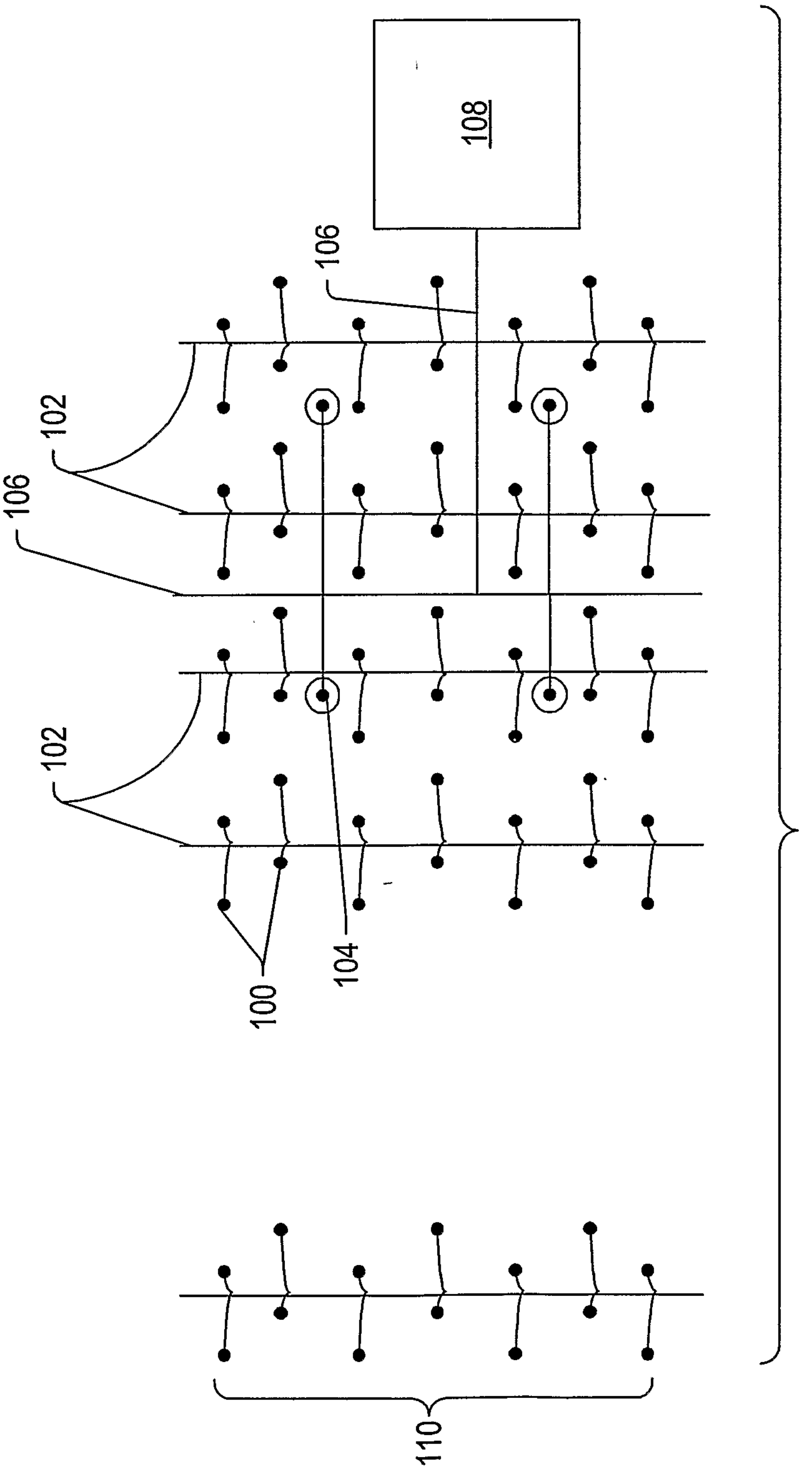

FIG. 2

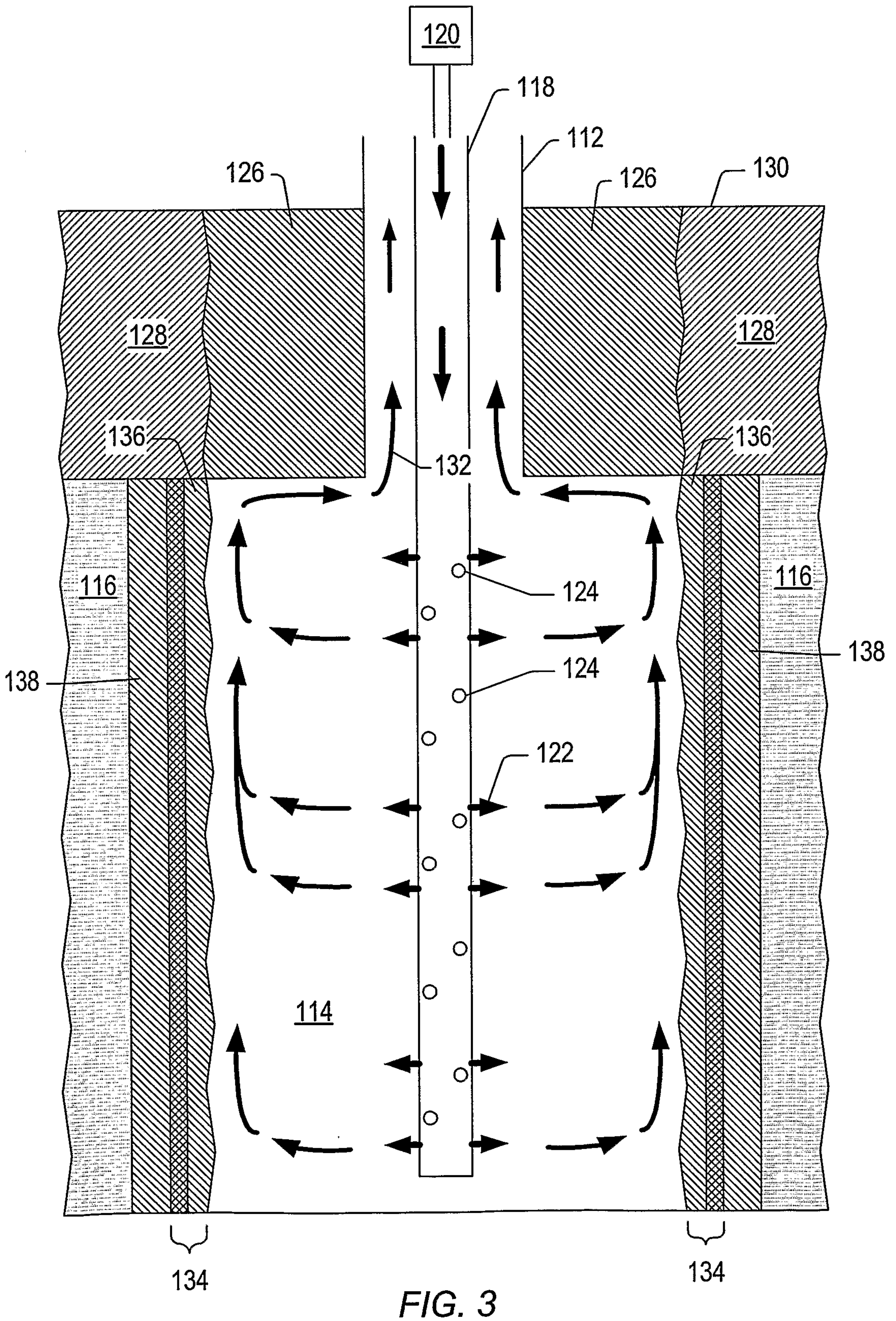
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FIG. 3

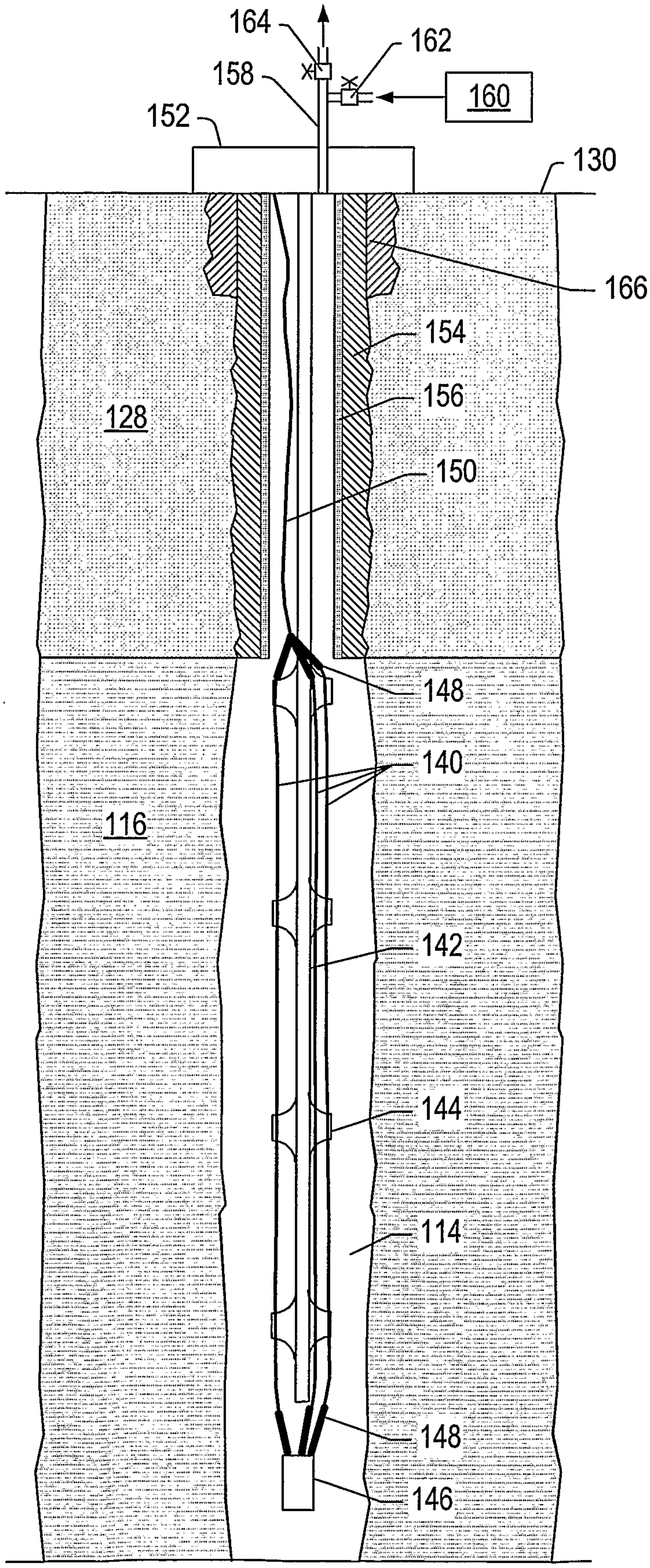

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FIG. 4

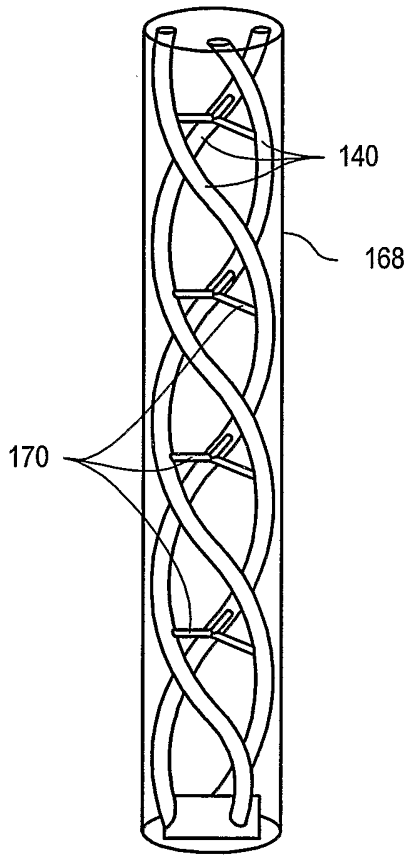

FIG. 5

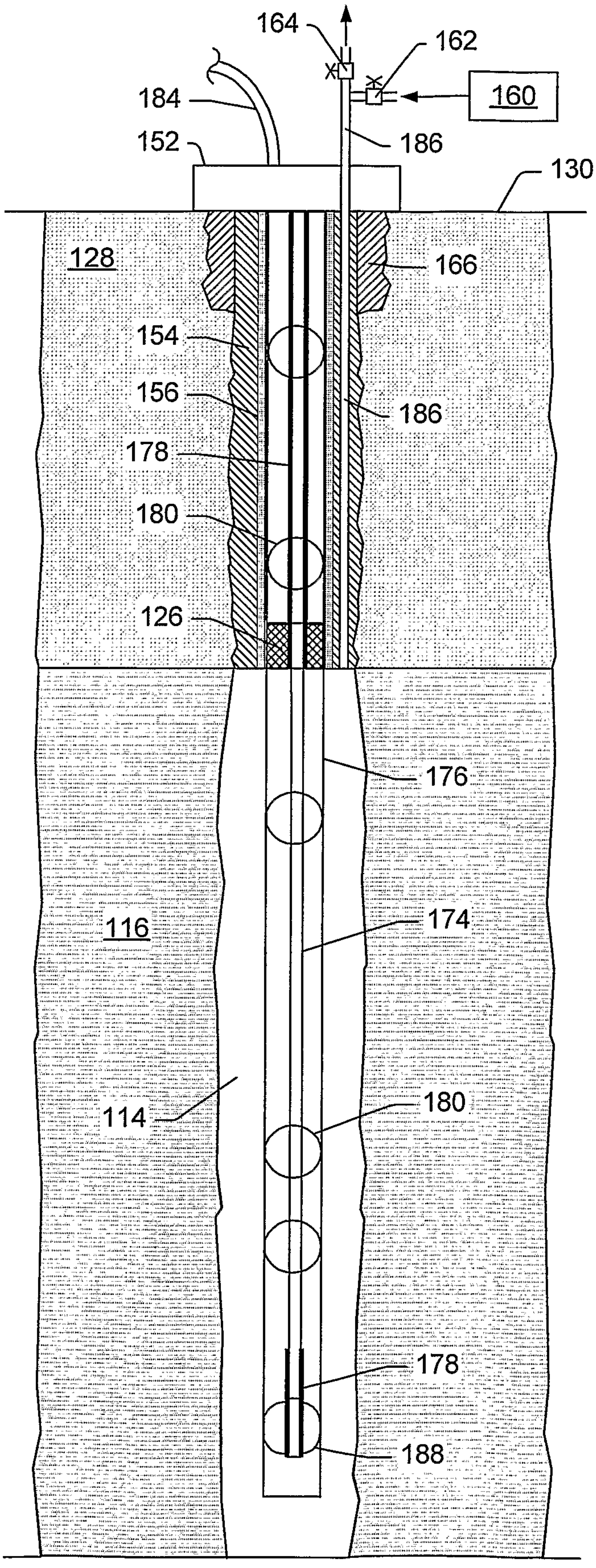
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FIG. 6

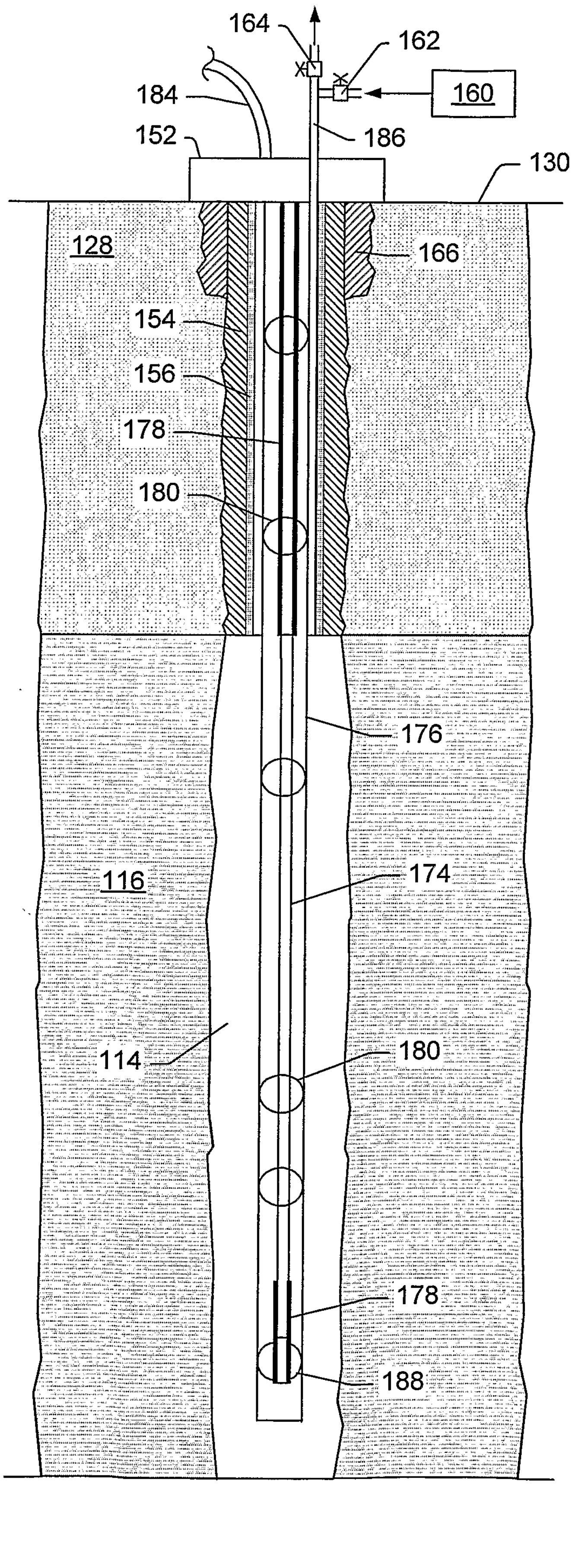
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FIG. 7

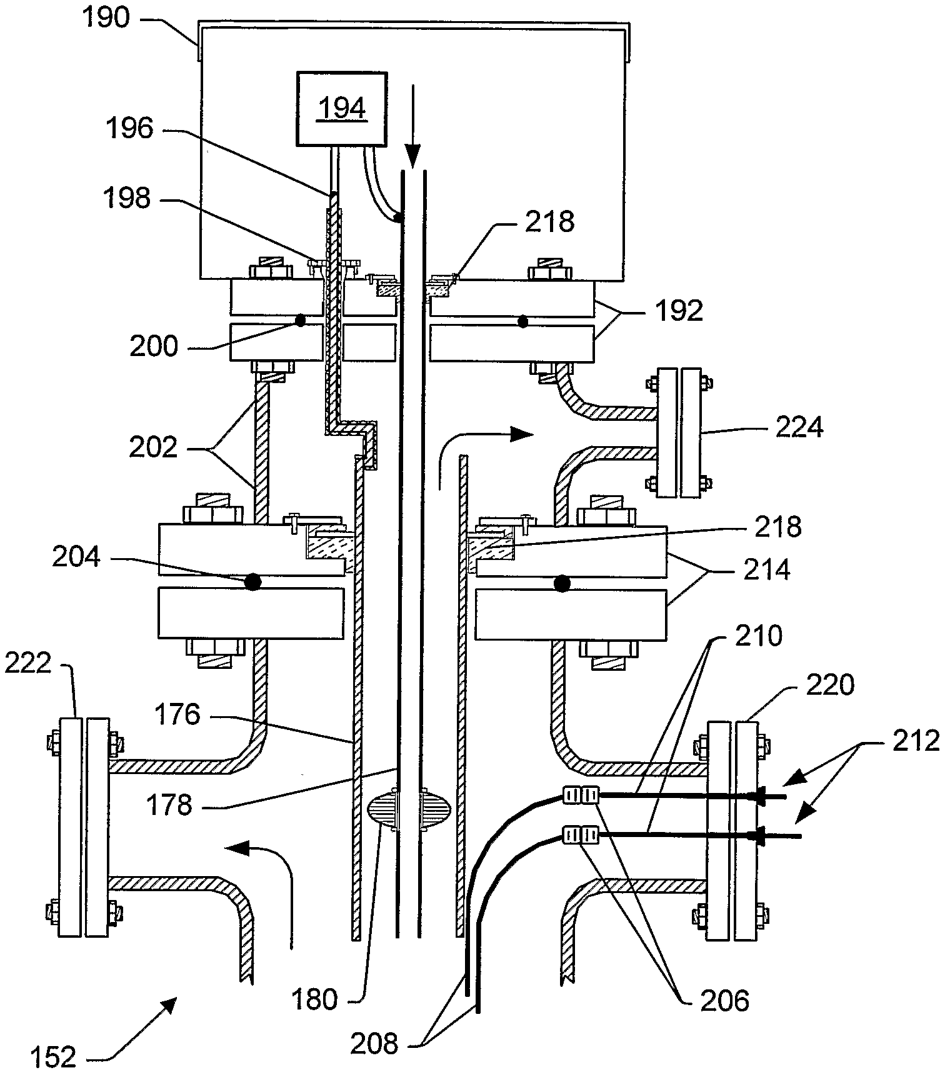
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FIG. 8

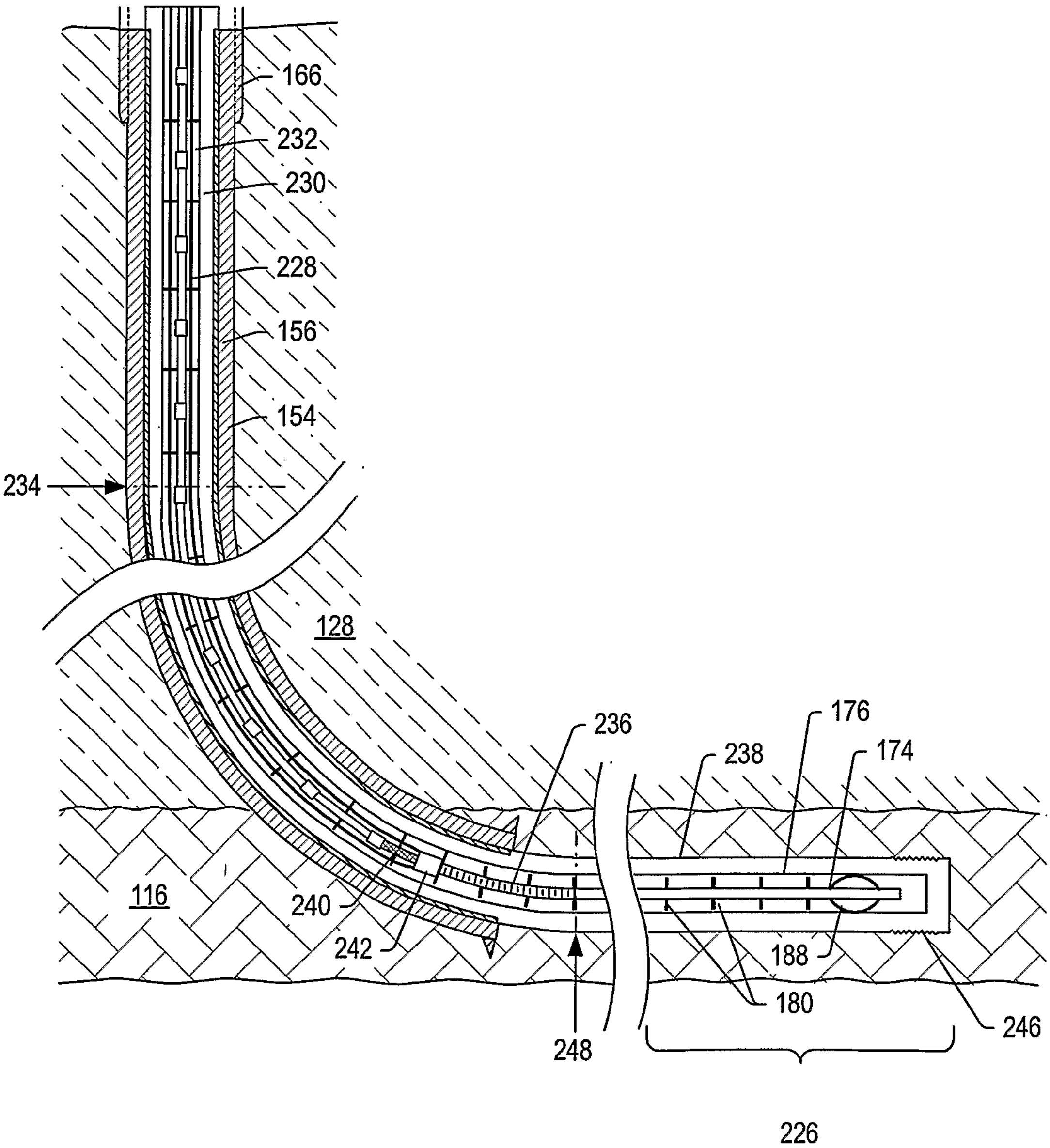
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FIG. 9

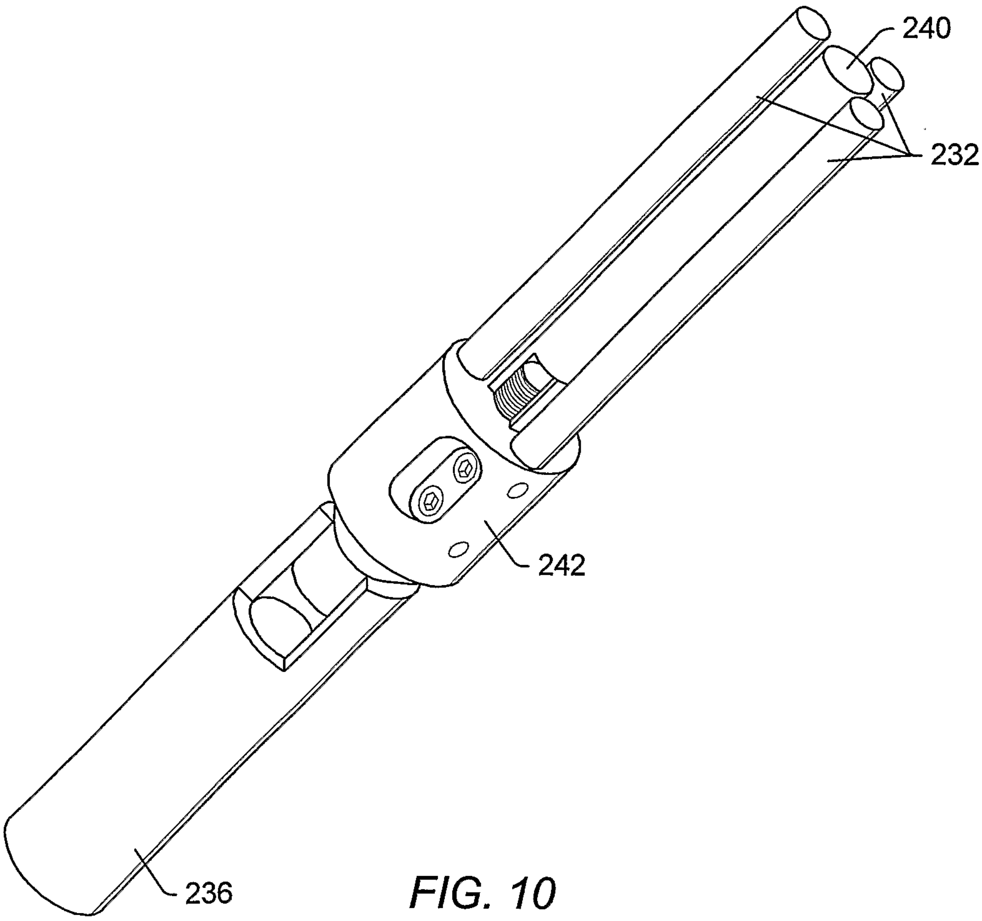

FIG. 10

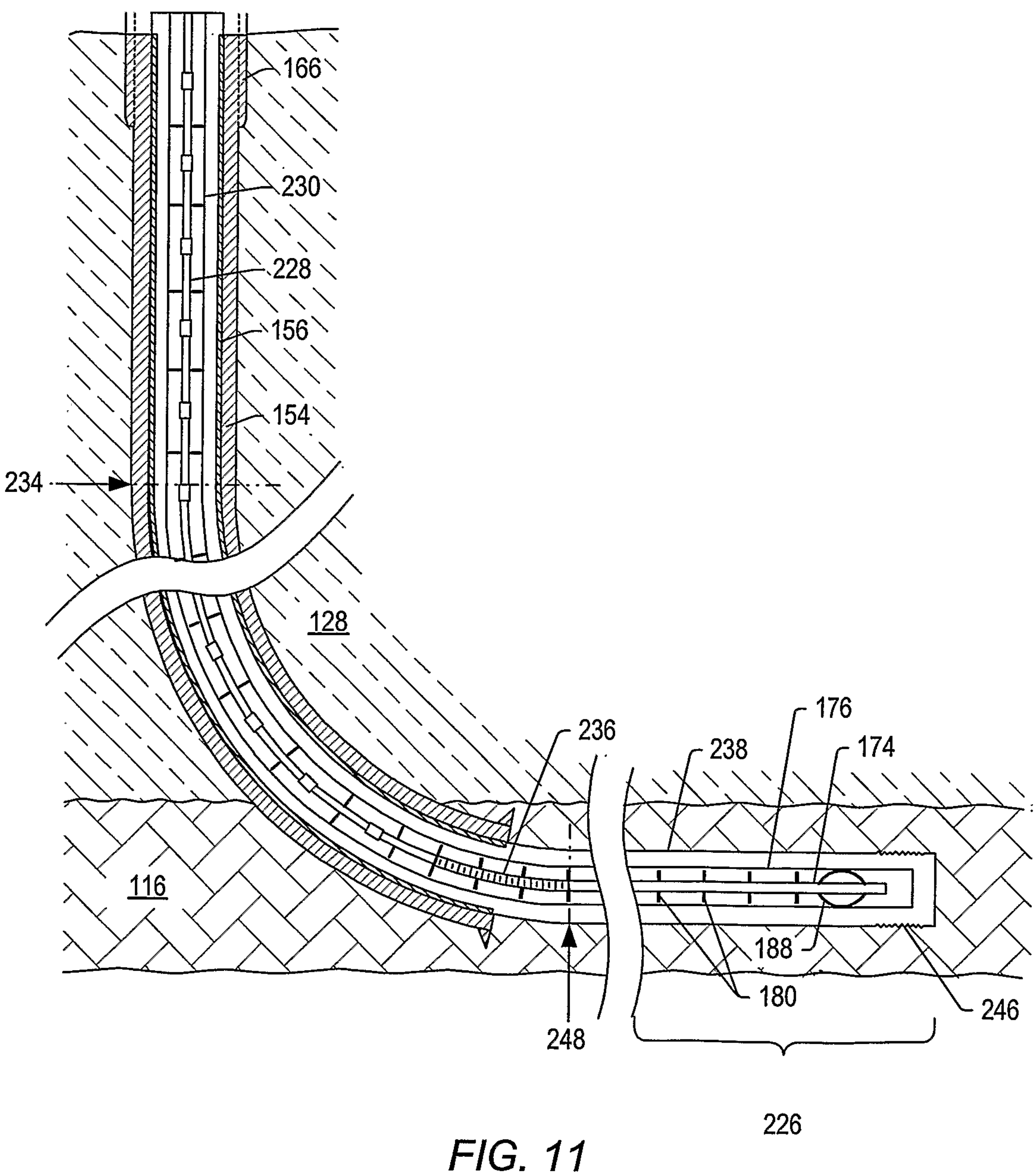
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FIG. 11

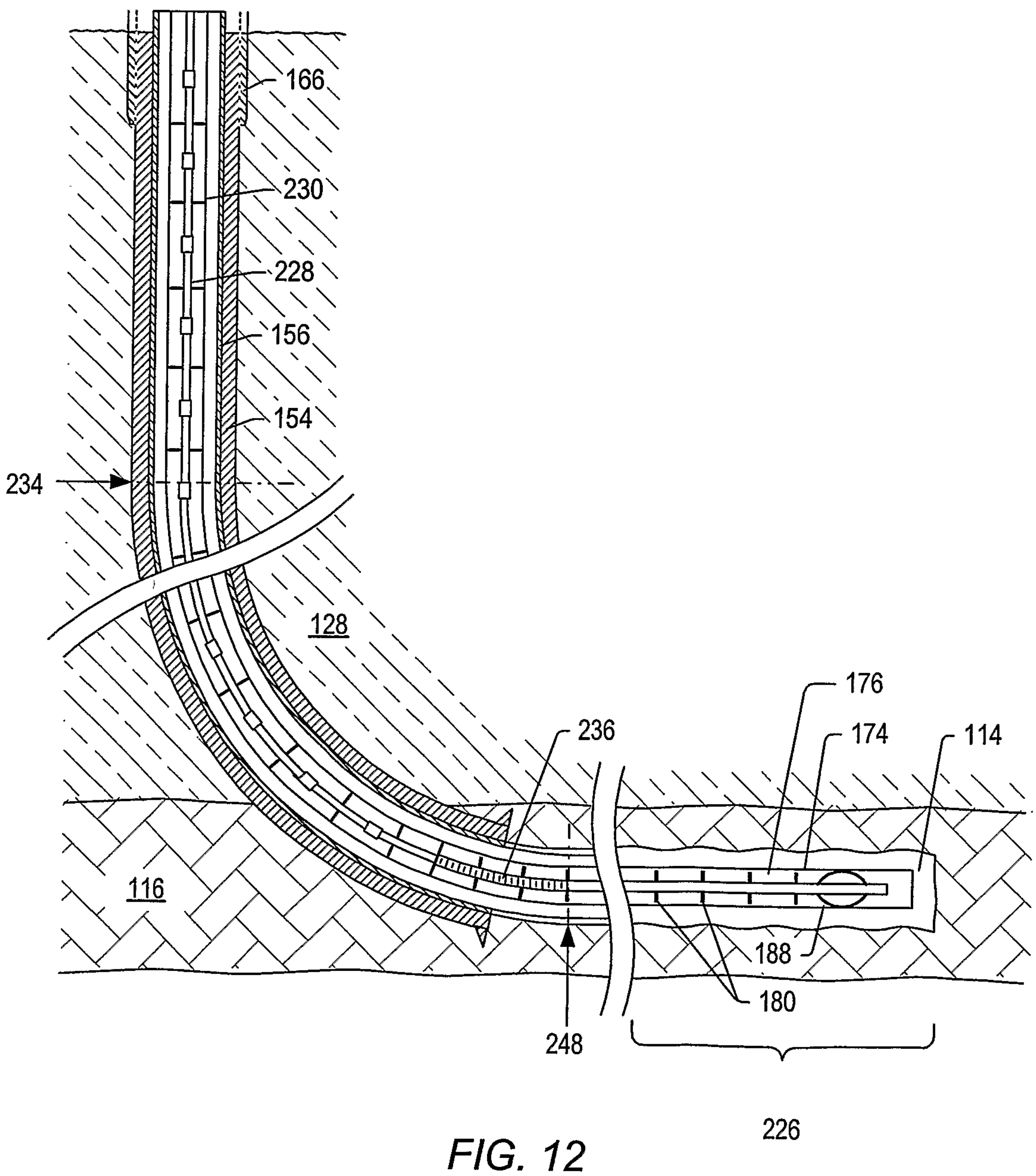

FIG. 12

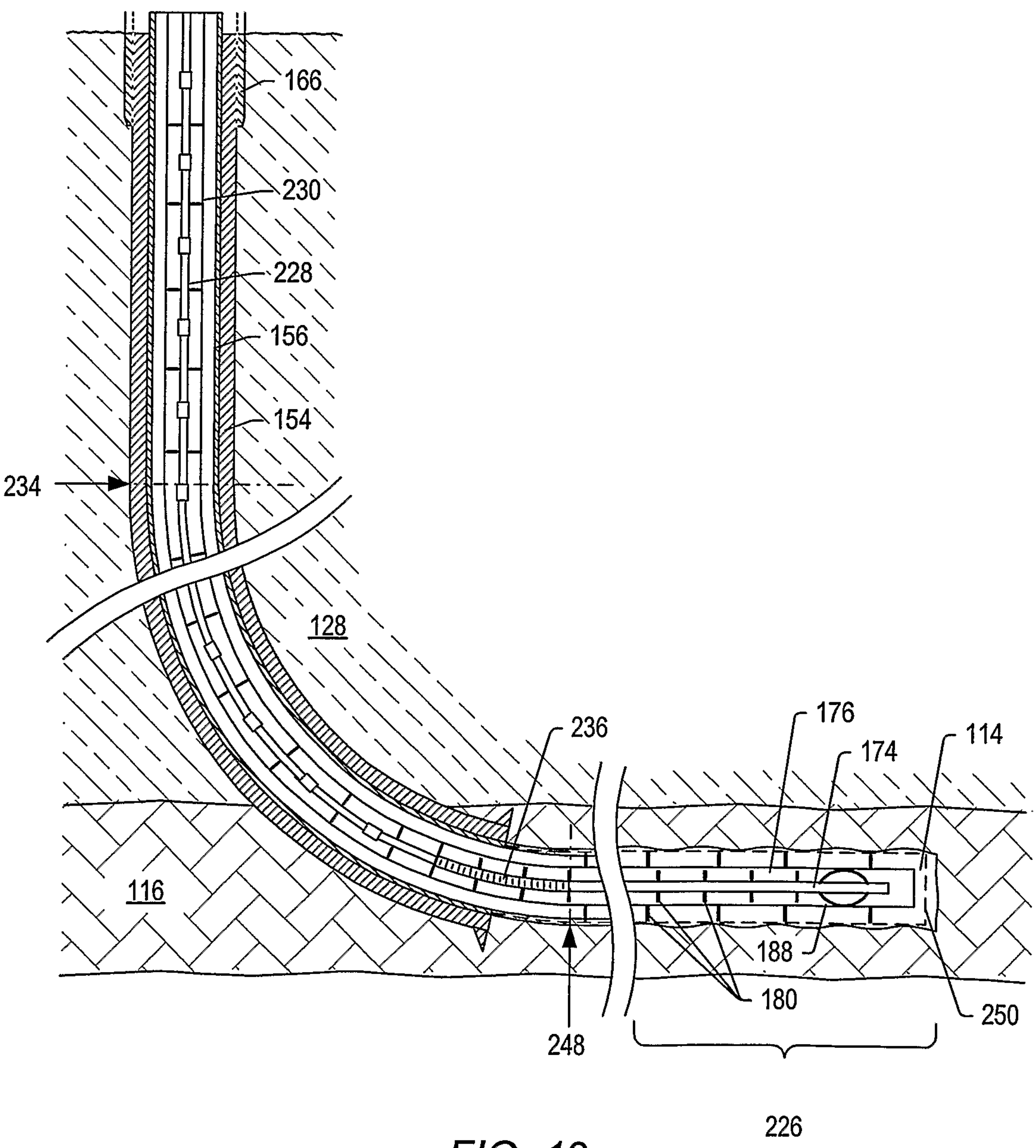
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FIG. 13

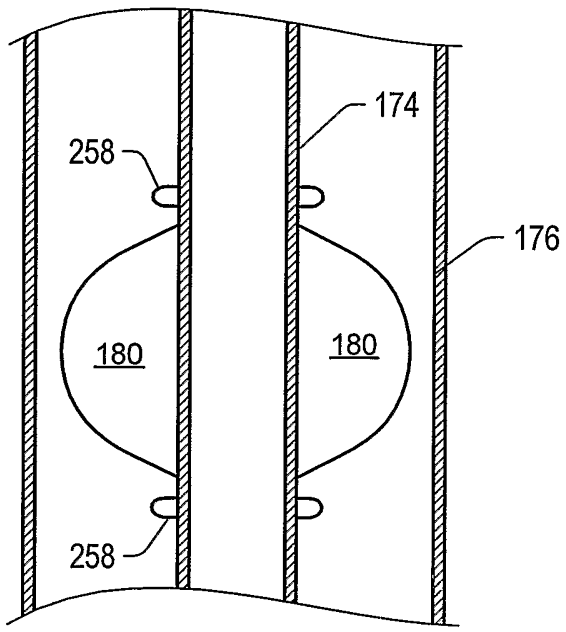

FIG. 14

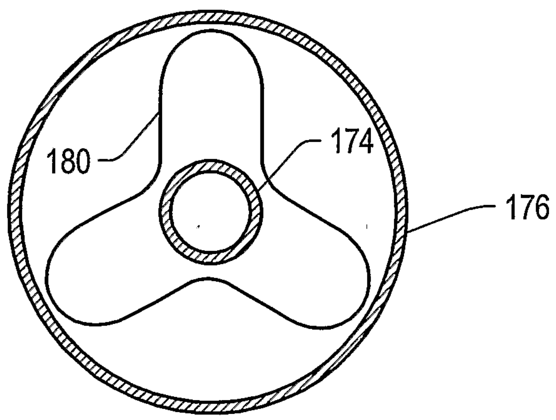

FIG. 15

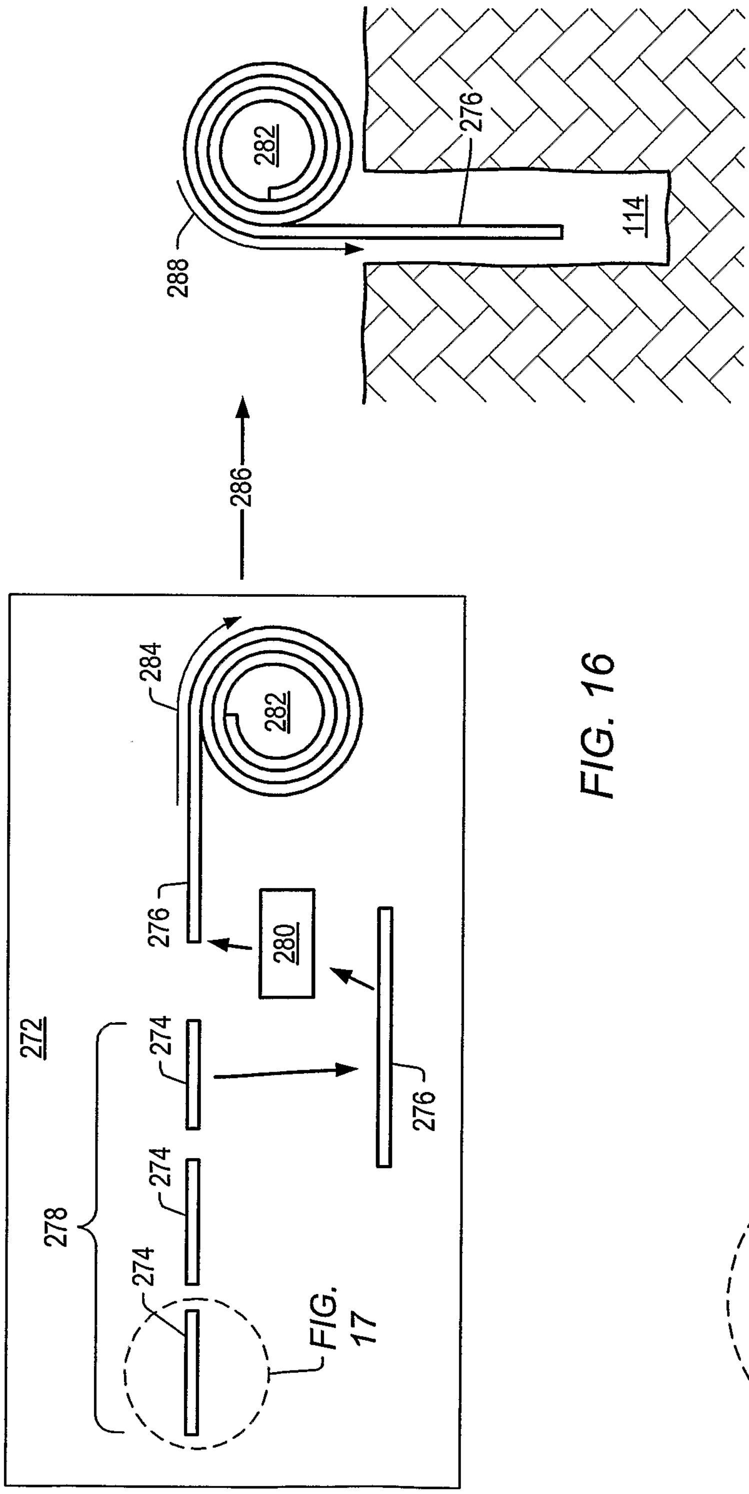
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FIG. 17
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FIG. 16

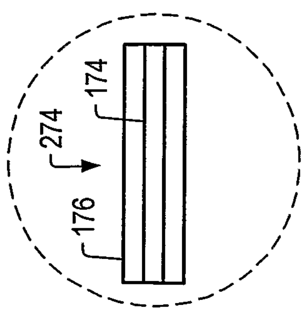
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FIG. 17

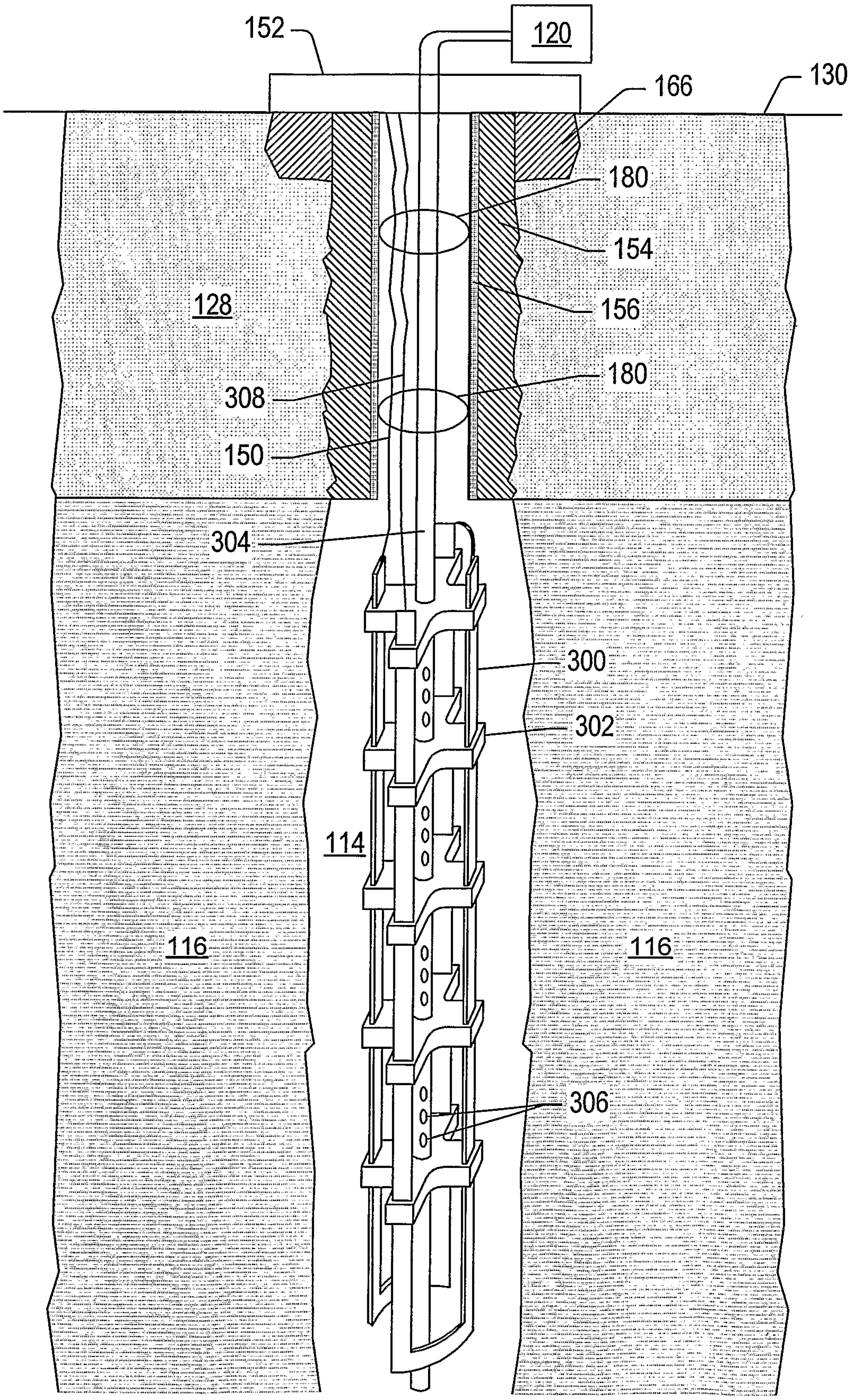

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FIG. 18