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(54) **Title:** IN SITU HEAT TREATMENT FROM MULTIPLE LAYERS OF A TAR SANDS FORMATION

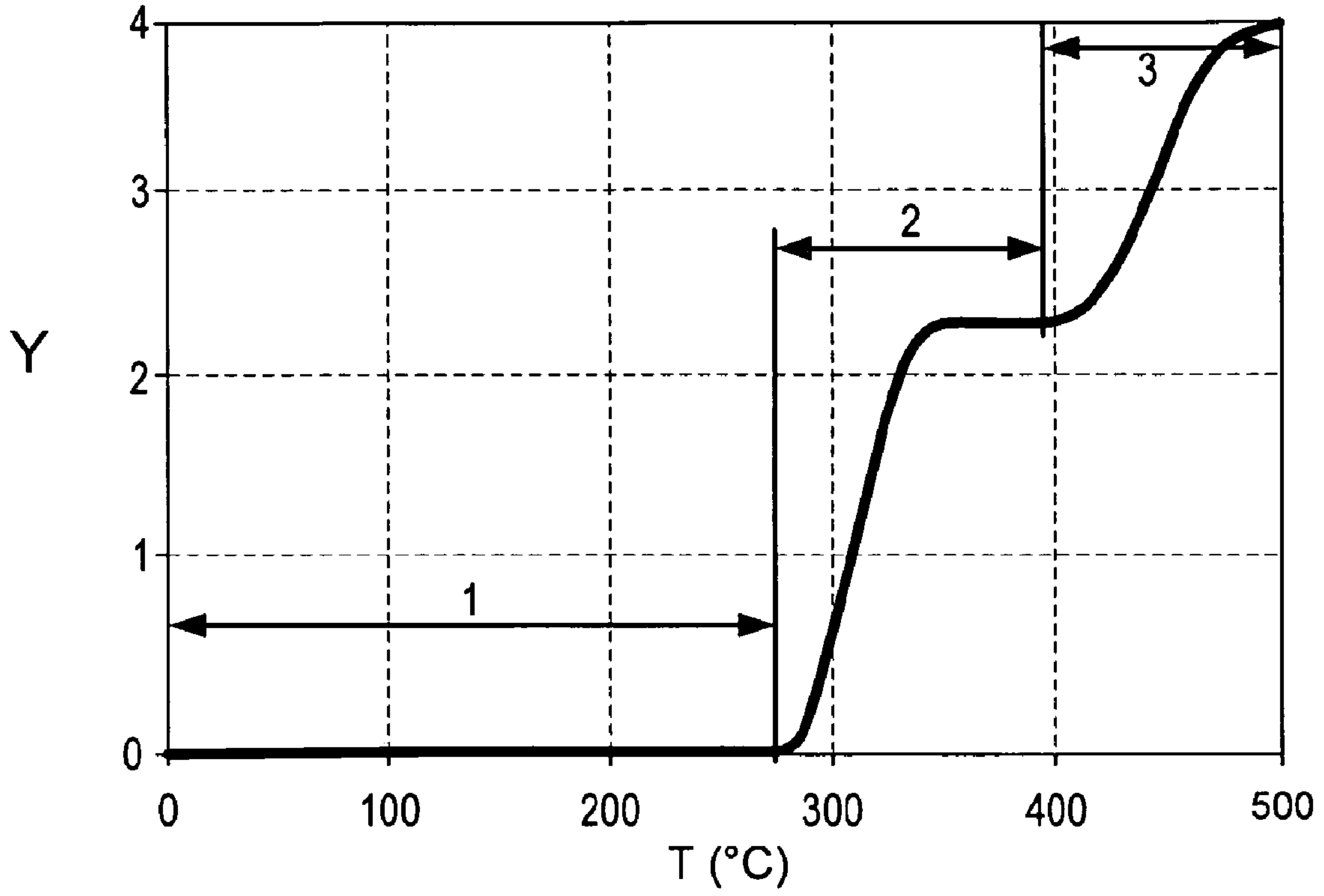

FIG. 1

(57) **Abrégé/Abstract:**

A method for treating a tar sands formation is disclosed. The method includes providing a drive fluid to a first hydrocarbon containing layer of the formation to mobilize at least some hydrocarbons in the first layer. At least some of the mobilized

(57) **Abrégé(suite)/Abstract(continued):**

hydrocarbons are allowed to flow into a second hydrocarbon containing layer of the formation. Heat is provided to the second layer from one or more heaters located in the second layer. At least some hydrocarbons are produced from the second layer of the formation.

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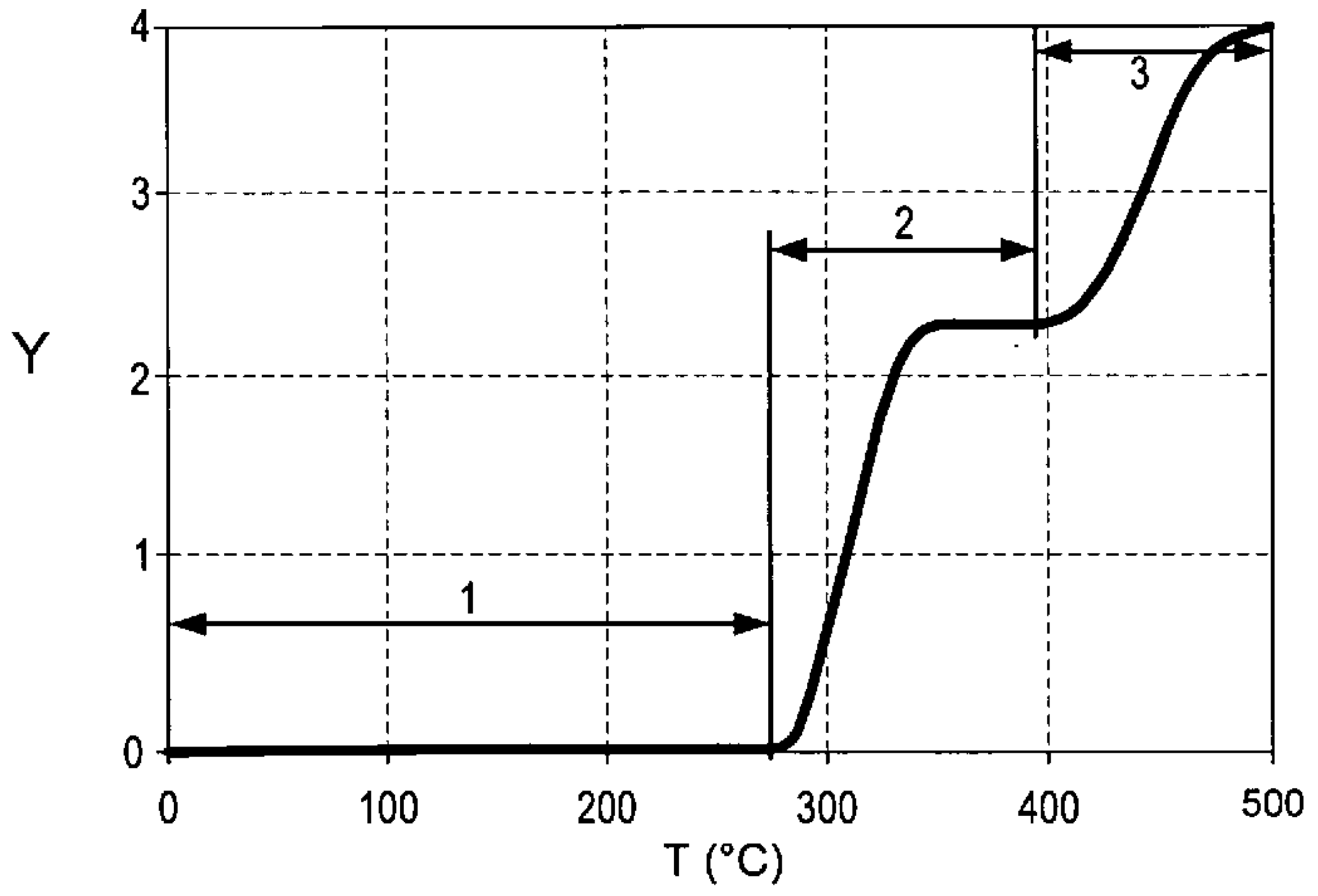

FIG. 1

(57) Abstract: A method for treating a tar sands formation is disclosed. The method includes providing a drive fluid to a first hydrocarbon containing layer of the formation to mobilize at least some hydrocarbons in the first layer. At least some of the mobilized hydrocarbons are allowed to flow into a second hydrocarbon containing layer of the formation. Heat is provided to the second layer from one or more heaters located in the second layer. At least some hydrocarbons are produced from the second layer of the formation.

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IN SITU HEAT TREATMENT FROM MULTIPLE LAYERS OF A TAR SANDS FORMATION

BACKGROUND

1. Field of the Invention

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

2. Description of Related Art

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

[0003] Large deposits of heavy hydrocarbons (heavy oil and/or tar) contained in relatively permeable formations (for example in tar sands) are found in North America, South America, Africa, and Asia. Tar can be surface-mined and upgraded to lighter hydrocarbons such as crude oil, naphtha, kerosene, and/or gas oil. Surface milling processes may further separate the bitumen from sand. The separated bitumen may be converted to light hydrocarbons using conventional refinery methods. Mining and upgrading tar sand is usually substantially more expensive than producing lighter hydrocarbons from conventional oil reservoirs.

[0004] In situ production of hydrocarbons from tar sand may be accomplished by heating and/or injecting a gas into the formation. U.S. Patent Nos. 5,211,230 to Ostapovich et al. and 5,339,897 to Leaute describe a horizontal production well located in an oil-bearing reservoir. A vertical conduit may be used to inject an oxidant gas into the reservoir for in situ combustion.

[0005] U.S. Patent No. 2,780,450 to Ljungstrom describes heating bituminous geological formations in situ to convert or crack a liquid tar-like substance into oils and gases.

[0006] U.S. Patent No. 4,597,441 to Ware et al. describes contacting oil, heat, and hydrogen simultaneously in a reservoir. Hydrogenation may enhance recovery of oil from the reservoir.

[0007] U.S. Patent No. 5,046,559 to Glandt and 5,060,726 to Glandt et al. describe preheating a portion of a tar sand formation between an injector well and a producer well. Steam may be injected from the injector well into the formation to produce hydrocarbons at the producer well.

[0008] 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 such as tar sands formations. Some tar sands formations include two or more layers of hydrocarbons with different physical properties. Thus, there is a need for methods and systems for efficiently producing hydrocarbons from the multiple layers of the tar sands formations.

SUMMARY

[0009] Embodiments described herein generally relate to systems, methods, and heaters for treating a subsurface formation. Embodiments described herein also generally relate to heaters that have novel components therein. Such heaters can be obtained by using the systems and methods described herein.

[0010] In certain embodiments, the invention provides one or more systems, methods, and/or heaters. In some embodiments, the systems, methods, and/or heaters are used for treating a subsurface formation.

[0011] In certain embodiments, the invention provides a method for treating a tar sands formation, comprising: providing a drive fluid to a first hydrocarbon containing layer of the formation to mobilize at least some hydrocarbons in the first layer; allowing at least some of the mobilized hydrocarbons to flow into a second hydrocarbon containing layer of the formation; providing heat to the second layer from one or more heaters located in the second layer; and producing at least some hydrocarbons from the second layer of the formation.

[0012] In further embodiments, features from specific embodiments may be combined with features from other embodiments. For example, features from one embodiment may be combined with features from any of the other embodiments.

[0013] In further embodiments, treating a subsurface formation is performed using any of the methods, systems, or heaters described herein.

[0014] In further embodiments, additional features may be added to the specific embodiments described herein.

BRIEF DESCRIPTION OF THE DRAWINGS

[0015] Advantages of the present invention may become apparent to those skilled in the art with the benefit of the following detailed description and upon reference to the accompanying drawings in which:

[0016] FIG. 1 depicts an illustration of stages of heating a hydrocarbon containing formation.

[0017] FIG. 2 shows a schematic view of an embodiment of a portion of an in situ heat treatment system for treating a hydrocarbon containing formation.

[0018] FIG. 3 depicts a representation of an embodiment for producing hydrocarbons from a tar sands formation.

[0019] FIG. 4 depicts a representation of an embodiment for producing hydrocarbons from multiple layers in a tar sands formation.

[0020] 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

[0021] The following description generally relates to systems and methods for treating hydrocarbons in the formations. Such formations may be treated to yield hydrocarbon products, hydrogen, and other products.

[0022] "API gravity" refers to API gravity at 15.5 °C (60 °F). API gravity is as determined by ASTM Method D6822 or ASTM Method D1298.

[0023] “Fluid pressure” is a pressure generated by a fluid in a formation. “Lithostatic pressure” (sometimes referred to as “lithostatic stress”) is a pressure in a formation equal to a weight per unit area of an overlying rock mass. “Hydrostatic pressure” is a pressure in a formation exerted by a column of water.

[0024] A “formation” includes one or more hydrocarbon containing layers, one or more non-hydrocarbon layers, an overburden, and/or an underburden. “Hydrocarbon layers” refer to layers in the formation that contain hydrocarbons. The hydrocarbon layers may contain non-hydrocarbon material and hydrocarbon material. The “overburden” and/or the “underburden” include one or more different types of impermeable materials. For example, the overburden and/or underburden may include rock, shale, mudstone, or wet/tight carbonate. In some embodiments of in situ heat treatment processes, the overburden and/or the underburden may include a hydrocarbon containing layer or hydrocarbon containing layers that are relatively impermeable and are not subjected to temperatures during in situ heat treatment processing that result in significant characteristic changes of the hydrocarbon containing layers of the overburden and/or the underburden. For example, the underburden may contain shale or mudstone, but the underburden is not allowed to heat to pyrolysis temperatures during the in situ heat treatment process. In some cases, the overburden and/or the underburden may be somewhat permeable.

[0025] “Formation fluids” refer to fluids present in a formation and may include pyrolyzation fluid, synthesis gas, mobilized hydrocarbons, and water (steam). Formation fluids may include hydrocarbon fluids as well as non-hydrocarbon fluids. The term “mobilized fluid” refers to fluids in a hydrocarbon containing formation that are able to flow as a result of thermal treatment of the formation. “Produced fluids” refer to fluids removed from the formation.

[0026] A “heat source” is any system for providing heat to at least a portion of a formation substantially by conductive and/or radiative heat transfer. For example, a heat source may include electric heaters such as an insulated conductor, an elongated member, and/or a conductor disposed in a conduit. A heat source may also include systems that generate heat by burning a fuel external to or in a formation. The systems may be surface burners, downhole gas burners, flameless distributed combustors, and natural distributed combustors. In some embodiments, heat provided to or generated in one or more heat sources may be supplied by other sources of energy. The other sources of energy may directly heat a formation, or the energy may be applied to a transfer medium that directly or indirectly heats the formation. It is to be understood that one or more heat sources that are applying heat to a formation may use different sources of energy. Thus, for example, for a given formation some heat sources may supply heat from electric resistance heaters, some heat sources may provide heat from combustion, and some heat sources may provide heat from one or more other energy sources (for example, chemical reactions, solar energy, wind energy, biomass, or other sources of renewable energy). A chemical reaction may include an exothermic reaction (for example, an oxidation reaction). A heat source may also include a heater that provides heat to a zone proximate and/or surrounding a heating location such as a heater well.

[0027] A “heater” is any system or heat source for generating heat in a well or a near wellbore region. Heaters may be, but are not limited to, electric heaters, burners, combustors that react with material in or produced from a formation, and/or combinations thereof.

[0028] “Heavy hydrocarbons” are viscous hydrocarbon fluids. Heavy hydrocarbons may include highly viscous hydrocarbon fluids such as heavy oil, tar, and/or asphalt. Heavy hydrocarbons may include carbon and hydrogen, as well as smaller concentrations of sulfur, oxygen, and nitrogen. Additional elements may also be present in heavy hydrocarbons in trace amounts. Heavy hydrocarbons may be classified by API gravity. Heavy hydrocarbons generally have an API gravity below about 20°. Heavy oil, for example, generally has an API gravity of about 10-20°, whereas tar generally has an API gravity below about 10°. The viscosity of heavy hydrocarbons is generally greater than about 100 centipoise at 15 °C. Heavy hydrocarbons may include aromatics or other complex ring hydrocarbons.

[0029] Heavy hydrocarbons may be found in a relatively permeable formation. The relatively permeable formation may include heavy hydrocarbons entrained in, for example, sand or carbonate. “Relatively permeable” is defined, with respect to formations or portions thereof, as an average permeability of 10 millidarcy or more (for example, 10 or 100 millidarcy). “Relatively low permeability” is defined, with respect to formations or portions thereof, as an average permeability of less than about 10 millidarcy. One darcy is equal to about 0.99 square micrometers. An impermeable layer generally has a permeability of less than about 0.1 millidarcy.

[0030] Certain types of formations that include heavy hydrocarbons may also include, but are not limited to, natural mineral waxes, or natural asphaltites. “Natural mineral waxes” typically occur in substantially tubular veins that may be several meters wide, several kilometers long, and hundreds of meters deep. "Natural asphaltites" include solid hydrocarbons of an aromatic composition and typically occur in large veins. In situ recovery of hydrocarbons from formations such as natural mineral waxes and natural asphaltites may include melting to form liquid hydrocarbons and/or solution mining of hydrocarbons from the formations.

[0031] "Hydrocarbons" are generally defined as molecules formed primarily by carbon and hydrogen atoms. Hydrocarbons may also include other elements such as, but not limited to, halogens, metallic elements, nitrogen, oxygen, and/or sulfur. Hydrocarbons may be, but are not limited to, kerogen, bitumen, pyrobitumen, oils, natural mineral waxes, and asphaltites. Hydrocarbons may be located in or adjacent to mineral matrices in the earth. Matrices may include, but are not limited to, sedimentary rock, sands, silicilytes, carbonates, diatomites, and other porous media. "Hydrocarbon fluids" are fluids that include hydrocarbons. Hydrocarbon fluids may include, entrain, or be entrained in non-hydrocarbon fluids such as hydrogen, nitrogen, carbon monoxide, carbon dioxide, hydrogen sulfide, water, and ammonia.

[0032] An "in situ conversion process" refers to a process of heating a hydrocarbon containing formation from heat sources to raise the temperature of at least a portion of the formation above a pyrolysis temperature so that pyrolyzation fluid is produced in the formation.

[0033] An "in situ heat treatment process" refers to a process of heating a hydrocarbon containing formation with heat sources to raise the temperature of at least a portion of the formation above a temperature that results in mobilized fluid, visbreaking, and/or pyrolysis of hydrocarbon containing material so that mobilized fluids, visbroken fluids, and/or pyrolyzation fluids are produced in the formation.

[0034] "Pyrolysis" is the breaking of chemical bonds due to the application of heat. For example, pyrolysis may include transforming a compound into one or more other substances by heat alone. Heat may be transferred to a section of the formation to cause pyrolysis.

[0035] "Pyrolyzation fluids" or "pyrolysis products" refers to fluid produced substantially during pyrolysis of hydrocarbons. Fluid produced by pyrolysis reactions may mix with other fluids in a formation. The mixture would be considered pyrolyzation fluid or pyrolyzation product. As used herein, "pyrolysis zone" refers to a volume of a formation (for example, a relatively permeable formation such as a tar sands formation) that is reacted or reacting to form a pyrolyzation fluid.

[0036] "Superposition of heat" refers to providing heat from two or more heat sources to a selected section of a formation such that the temperature of the formation at least at one location between the heat sources is influenced by the heat sources.

[0037] "Tar" is a viscous hydrocarbon that generally has a viscosity greater than about 10,000 centipoise at 15 °C. The specific gravity of tar generally is greater than 1.000. Tar may have an API gravity less than 10°.

[0038] A "tar sands formation" is a formation in which hydrocarbons are predominantly present in the form of heavy hydrocarbons and/or tar entrained in a mineral grain framework or other host lithology (for example, sand or carbonate). Examples of tar sands formations include formations such as the Athabasca formation, the Grosmont formation, and the Peace River formation, all three in Alberta, Canada; and the Faja formation in the Orinoco belt in Venezuela.

[0039] "Thickness" of a layer refers to the thickness of a cross section of the layer, wherein the cross section is normal to a face of the layer.

[0040] "Upgrade" refers to increasing the quality of hydrocarbons. For example, upgrading heavy hydrocarbons may result in an increase in the API gravity of the heavy hydrocarbons.

[0041] "Visbreaking" refers to the untangling of molecules in fluid during heat treatment and/or to the breaking of large molecules into smaller molecules during heat treatment, which results in a reduction of the viscosity of the fluid.

[0042] "Viscosity" refers to kinematic viscosity at 40 °C unless specified. Viscosity is as determined by ASTM Method D445.

[0043] The term "wellbore" refers to a hole in a formation made by drilling or insertion of a conduit into the formation. A wellbore may have a substantially circular cross section, or another cross-sectional shape. As used herein, the terms "well" and "opening," when referring to an opening in the formation may be used interchangeably with the term "wellbore."

[0044] Hydrocarbons in formations may be treated in various ways to produce many different products. In certain embodiments, hydrocarbons in formations are treated in stages. FIG. 1 depicts an illustration of stages of heating the hydrocarbon containing formation. FIG. 1 also depicts an example of yield ("Y") in barrels of oil equivalent per ton (y axis) of formation fluids from the formation versus temperature ("T") of the heated formation in degrees Celsius (x axis).

[0045] Desorption of methane and vaporization of water occurs during stage 1 heating. Heating of the formation through stage 1 may be performed as quickly as possible. For example, when the hydrocarbon containing formation is initially heated, hydrocarbons in the formation desorb adsorbed methane. The desorbed methane may be produced from the formation. If the hydrocarbon containing formation is heated further, water in the hydrocarbon containing formation is vaporized. Water may occupy, in some hydrocarbon containing formations, between 10% and 50% of the pore volume in the formation. In other formations, water occupies larger or smaller portions of the pore volume. Water typically is vaporized in a formation between 160 °C and 285 °C at pressures of 600 kPa absolute to 7000 kPa absolute. In some embodiments, the vaporized water produces wettability changes in the formation and/or increased formation pressure. The wettability changes and/or increased pressure may affect pyrolysis reactions or other reactions in the formation. In certain embodiments, the vaporized water is produced from the formation. In other embodiments, the vaporized water is used for steam extraction and/or distillation in the formation or outside the formation. Removing the water from and increasing the pore volume in the formation increases the storage space for hydrocarbons in the pore volume.

[0046] In certain embodiments, after stage 1 heating, the formation is heated further, such that a temperature in the formation reaches (at least) an initial pyrolyzation temperature (such as a temperature at the lower end of the temperature range shown as stage 2). Hydrocarbons in the formation may be pyrolyzed throughout stage 2. A pyrolysis temperature range varies depending on the types of hydrocarbons in the formation. The pyrolysis temperature range may include temperatures between 250 °C and 900 °C. The pyrolysis temperature range for producing desired products may extend through only a portion of the total pyrolysis temperature range. In some embodiments, the pyrolysis temperature range for producing desired products may include temperatures between 250 °C and 400 °C or temperatures between 270 °C and 350 °C. If a temperature of hydrocarbons in the formation is slowly raised through the temperature range from 250 °C to 400 °C, production of pyrolysis products may be substantially complete when the temperature approaches 400 °C. Average temperature of the hydrocarbons may be raised at a rate of less than 5 °C per day, less than 2 °C per day, less than 1 °C per day, or less than 0.5 °C per day through the pyrolysis temperature range for producing desired products. Heating the hydrocarbon containing formation with a plurality of heat sources may establish thermal gradients around the heat sources that slowly raise the temperature of hydrocarbons in the formation through the pyrolysis temperature range.

[0047] The rate of temperature increase through the pyrolysis temperature range for desired products may affect the quality and quantity of the formation fluids produced from the hydrocarbon containing formation. Slowly raising the temperature of the formation through the pyrolysis temperature range for desired products may allow for the production of high quality, high API gravity hydrocarbons from the formation. Slowly raising the temperature of the formation through the pyrolysis temperature range for desired products may allow for the removal of a large amount of the hydrocarbons present in the formation as hydrocarbon product.

[0048] In some in situ heat treatment embodiments, a portion of the formation is heated to a desired temperature instead of slowly heating the temperature through a temperature range. In some embodiments, the desired temperature is 300 °C, 325 °C, or 350 °C. Other temperatures may be selected as the desired temperature. Superposition of heat from heat sources allows the desired temperature to be relatively quickly and efficiently established in the formation. Energy input into the formation from the heat sources may be adjusted to maintain the temperature in the formation substantially at the desired temperature. The heated portion of the formation is maintained substantially at the desired temperature until pyrolysis declines such that production of desired formation fluids from the formation becomes uneconomical. Parts of the formation that are subjected to pyrolysis may include regions brought into a pyrolysis temperature range by heat transfer from only one heat source.

[0049] In certain embodiments, formation fluids including pyrolyzation fluids are produced from the formation. As the temperature of the formation increases, the amount of condensable hydrocarbons in the produced formation fluid may decrease. At high temperatures, the formation may produce mostly methane and/or hydrogen. If the hydrocarbon containing formation is heated throughout an entire pyrolysis range, the formation may produce only small amounts of hydrogen towards an upper limit of the pyrolysis range. After all of the available hydrogen is depleted, a minimal amount of fluid production from the formation will typically occur.

[0050] After pyrolysis of hydrocarbons, a large amount of carbon and some hydrogen may still be present in the formation. A significant portion of carbon remaining in the formation can be produced from the formation in the form of synthesis gas. Synthesis gas generation may take place during stage 3 heating depicted in FIG. 1. Stage 3 may include heating a hydrocarbon containing formation to a temperature sufficient to allow synthesis gas generation. For example, synthesis gas may be produced in a temperature range from about 400 °C to about 1200 °C, about 500 °C to about 1100 °C, or about 550 °C to about 1000 °C. The temperature of the heated portion of the formation when the synthesis gas generating fluid is introduced to the formation determines the composition of synthesis gas produced in the formation. The generated synthesis gas may be removed from the formation through a production well or production wells.

[0051] Total energy content of fluids produced from the hydrocarbon containing formation may stay relatively constant throughout pyrolysis and synthesis gas generation. During pyrolysis at relatively low formation temperatures, a significant portion of the produced fluid may be condensable hydrocarbons that have a high energy content. At higher pyrolysis temperatures, however, less of the formation fluid may include condensable hydrocarbons. More non-condensable formation fluids may be produced from the formation. Energy content per unit volume of the produced fluid may decline slightly during generation of predominantly non-condensable formation fluids. During synthesis gas generation, energy content per unit volume of produced synthesis gas declines significantly compared to energy content of pyrolyzation fluid. The volume of the produced synthesis gas, however, will in many instances increase substantially, thereby compensating for the decreased energy content.

[0052] FIG. 2 depicts a schematic view of an embodiment of a portion of the in situ heat treatment system for treating the hydrocarbon containing formation. The in situ heat treatment system may include barrier wells 200. Barrier wells are used to form a barrier around a treatment area. The barrier inhibits fluid flow into and/or out of the treatment area. Barrier wells include, but are not limited to, dewatering wells, vacuum wells, capture wells, injection wells, grout wells, freeze wells, or combinations thereof. In some embodiments, barrier wells 200 are dewatering wells. Dewatering wells may remove liquid water and/or inhibit liquid water from entering a portion of the formation to be heated, or to the formation being heated. In the embodiment depicted in FIG. 2, the barrier wells 200 are shown extending only along one side of heat sources 202, but the barrier wells typically encircle all heat sources 202 used, or to be used, to heat a treatment area of the formation.

[0053] Heat sources 202 are placed in at least a portion of the formation. Heat sources 202 may include heaters such as insulated conductors, conductor-in-conduit heaters, surface burners, flameless distributed combustors, and/or natural distributed combustors. Heat sources 202 may also include other types of heaters. Heat sources 202 provide heat to at least a portion of the formation to heat hydrocarbons in the formation. Energy may be supplied to heat sources 202 through supply lines 204. Supply lines 204 may be structurally different depending on the type of heat source or heat sources used to heat the formation. Supply lines 204 for heat sources may transmit electricity for electric heaters, may transport fuel for combustors, or may transport heat exchange fluid that is circulated in the formation. In some embodiments, electricity for an in situ heat treatment process may be provided by a nuclear power plant or nuclear power plants. The use of nuclear power may allow for reduction or elimination of carbon dioxide emissions from the in situ heat treatment process.

[0054] Production wells 206 are used to remove formation fluid from the formation. In some embodiments, production well 206 includes a heat source. The heat source in the production well may heat one or more portions of the formation at or near the production well. In some in situ heat treatment process embodiments, the amount of heat supplied to the formation from the production well per meter of the production well is less than the amount of heat applied to the formation from a heat source that heats the formation per meter of the heat source.

[0055] In some embodiments, the heat source in production well 206 allows for vapor phase removal of formation fluids from the formation. Providing heating at or through the production well may: (1) inhibit condensation and/or refluxing of production fluid when such production fluid is moving in the production well proximate the overburden, (2) increase heat input into the formation, (3) increase production rate from the production well as compared to a production well without a heat source, (4) inhibit condensation of high carbon number compounds (C6 and above) in the production well, and/or (5) increase formation permeability at or proximate the production well.

[0056] Subsurface pressure in the formation may correspond to the fluid pressure generated in the formation. As temperatures in the heated portion of the formation increase, the pressure in the heated portion may increase as a result of thermal expansion of fluids, increased fluid generation, and vaporization of water. Controlling rate of fluid removal from the formation may allow for control of pressure in the formation. Pressure in the formation may be determined at a number of different locations, such as near or at production wells, near or at heat sources, or at monitor wells.

[0057] In some hydrocarbon containing formations, production of hydrocarbons from the formation is inhibited until at least some hydrocarbons in the formation have been pyrolyzed. Formation fluid may be produced from the formation when the formation fluid is of a selected quality. In some embodiments, the selected quality includes an API gravity of at least about 20°, 30°, or 40°. Inhibiting production until at least some hydrocarbons are pyrolyzed may increase conversion of heavy hydrocarbons to light hydrocarbons. Inhibiting initial production may minimize the production of heavy hydrocarbons from the formation. Production of substantial amounts of heavy hydrocarbons may require expensive equipment and/or reduce the life of production equipment.

[0058] After pyrolysis temperatures are reached and production from the formation is allowed, pressure in the formation may be varied to alter and/or control a composition of formation fluid produced, to control a percentage of condensable fluid as compared to non-condensable fluid in the formation fluid, and/or to control an API gravity of formation fluid being produced. For example, decreasing pressure may result in production of a larger condensable fluid component. The condensable fluid component may contain a larger percentage of olefins.

[0059] In some in situ heat treatment process embodiments, pressure in the formation may be maintained high enough to promote production of formation fluid with an API gravity of greater than 20°. Maintaining increased pressure in the formation may inhibit formation subsidence during in situ heat treatment. Maintaining increased pressure may facilitate vapor phase production of fluids from the formation. Vapor phase production may allow for a reduction in size of collection conduits used to transport fluids produced from the formation. Maintaining increased pressure may reduce or eliminate the need to compress formation fluids at the surface to transport the fluids in collection conduits to treatment facilities.

[0060] Maintaining increased pressure in a heated portion of the formation may surprisingly allow for production of large quantities of hydrocarbons of increased quality and of relatively low molecular weight. Pressure may be maintained so that formation fluid produced has a minimal amount of compounds above a selected carbon number. The selected carbon number may be at most 25, at most 20, at most 12, or at most 8. Some high carbon number compounds may be entrained in vapor in the formation and may be removed from the formation with the vapor. Maintaining increased pressure in the formation may inhibit entrainment of high carbon number compounds and/or multi-ring hydrocarbon compounds in the vapor. High carbon number compounds and/or multi-ring hydrocarbon compounds may remain in a liquid phase in the formation for significant time periods. The significant time periods may provide sufficient time for the compounds to pyrolyze to form lower carbon number compounds.

[0061] Formation fluid produced from production wells 206 may be transported through collection piping 208 to treatment facilities 210. Formation fluids may also be produced from heat sources 202. For example, fluid may be produced from heat sources 202 to control pressure in the formation adjacent to the heat sources. Fluid produced from heat sources 202 may be transported through tubing or piping to collection piping 208 or the produced fluid may be transported through tubing or piping directly to treatment facilities 210. Treatment facilities 210 may include separation units, reaction units, upgrading units, fuel cells, turbines, storage vessels, and/or other systems and units for processing produced formation fluids. The treatment facilities may form transportation fuel from at least a portion of the hydrocarbons produced from the formation. In some embodiments, the transportation fuel may be jet fuel, such as JP-8.

[0062] In certain embodiments, in situ heat treatment of the relatively permeable formation containing hydrocarbons (for example, the tar sands formation) includes heating the formation to visbreaking temperatures. For example, the formation may be heated to temperatures between about 100 °C and 260 °C, between about 150 °C and about 250 °C, between about 200 °C and about 240 °C, between about 205 °C and 230 °C, between about 210 °C and 225 °C. In one embodiment, the formation is heated to a temperature of about 220 °C. In one embodiment, the formation is heated to a temperature of about 230 °C. At visbreaking temperatures, fluids in the formation have a reduced viscosity (versus their initial viscosity at initial formation temperature) that allows fluids to flow in the formation. The reduced viscosity at visbreaking temperatures may be a permanent reduction in viscosity as the hydrocarbons go through a step change in viscosity at visbreaking temperatures (versus heating to mobilization temperatures, which may only temporarily reduce the viscosity). The visbroken fluids may have API gravities that are relatively low (for example, at most about 10°, about 12°, about 15°, or about 19° API gravity), but the

API gravities are higher than the API gravity of non-visbroken fluid from the formation. The non-visbroken fluid from the formation may have an API gravity of 7° or less.

[0063] In some embodiments, heaters in the formation are operated at full power output to heat the formation to visbreaking temperatures or higher temperatures. Operating at full power may rapidly increase the pressure in the formation. In certain embodiments, fluids are produced from the formation to maintain a pressure in the formation below a selected pressure as the temperature of the formation increases. In some embodiments, the selected pressure is a fracture pressure of the formation. In certain embodiments, the selected pressure is between about 1000 kPa and about 15000 kPa, between about 2000 kPa and about 10000 kPa, or between about 2500 kPa and about 5000 kPa. In one embodiment, the selected pressure is about 10000 kPa. Maintaining the pressure as close to the fracture pressure as possible may minimize the number of production wells needed for producing fluids from the formation.

[0064] In certain embodiments, treating the formation includes maintaining the temperature at or near visbreaking temperatures (as described above) during the entire production phase while maintaining the pressure below the fracture pressure. The heat provided to the formation may be reduced or eliminated to maintain the temperature at or near visbreaking temperatures. Heating to visbreaking temperatures but maintaining the temperature below pyrolysis temperatures or near pyrolysis temperatures (for example, below about 230 °C) inhibits coke formation and/or higher level reactions. Heating to visbreaking temperatures at higher pressures (for example, pressures near but below the fracture pressure) keeps produced gases in the liquid oil (hydrocarbons) in the formation and increases hydrogen reduction in the formation with higher hydrogen partial pressures. Heating the formation to only visbreaking temperatures also uses less energy input than heating the formation to pyrolysis temperatures.

[0065] Fluids produced from the formation may include visbroken fluids, mobilized fluids, and/or pyrolyzed fluids. In some embodiments, a produced mixture that includes these fluids is produced from the formation. The produced mixture may have assessable properties (for example, measurable properties). The produced mixture properties are determined by operating conditions in the formation being treated (for example, temperature and/or pressure in the formation). In certain embodiments, the operating conditions may be selected, varied, and/or maintained to produce desirable properties in hydrocarbons in the produced mixture. For example, the produced mixture may include hydrocarbons that have properties that allow the mixture to be easily transported (for example, sent through a pipeline without adding diluent or blending the mixture and/or resulting hydrocarbons with another fluid).

[0066] In certain embodiments, the amount of fluids produced at temperatures below visbreaking temperatures, the amount of fluids produced at visbreaking temperatures, the amount of fluids produced before reducing the pressure in the formation, and/or the amount of upgraded or pyrolyzed fluids produced may be varied to control the quality and amount of fluids produced from the formation and the total recovery of hydrocarbons from the formation. For example, producing more fluid during the early stages of treatment (for example, producing fluids before reducing the pressure in the formation) may increase the total recovery of hydrocarbons from the formation while reducing the overall quality (lowering the overall API gravity) of fluid produced from the formation. The overall quality is reduced because more heavy hydrocarbons are produced by producing more fluids at the lower temperatures. Producing less fluids at the lower temperatures may increase the overall quality of the fluids produced from the formation but may lower the total recovery of hydrocarbons from the formation. The total recovery may be lower because more coking occurs in the formation when less fluids are produced at lower temperatures.

[0067] In some embodiments, production of fluids is continued after reducing and/or turning off heating of the formation. The formation may be heated for a selected time. The formation may be heated until it reaches a selected average temperature. Production from the formation may continue after the selected time. Continuing production may produce more fluid from the formation as fluids drain towards the bottom of the formation and/or as fluids are upgraded by passing by hot spots in the formation. In some embodiments, a horizontal production well is located at or near the bottom of the formation (or a zone of the formation) to produce fluids after heating is turned down and/or off.

[0068] In certain embodiments, initially produced fluids (for example, fluids produced below visbreaking temperatures), fluids produced at visbreaking temperatures, and/or other viscous fluids produced from the formation are blended with diluent to produce fluids with lower viscosities. In some embodiments, the diluent includes upgraded or pyrolyzed fluids produced from the formation. In some embodiments, the diluent includes upgraded or pyrolyzed fluids produced from another portion of the formation or another formation. In certain embodiments, the amount of fluids produced at temperatures below visbreaking temperatures and/or fluids produced at visbreaking temperatures that are blended with upgraded fluids from the formation is adjusted to create a fluid suitable for transportation and/or use in a refinery. The amount of blending may be adjusted so that the fluid has chemical and physical stability. Maintaining the chemical and physical stability of the fluid may allow the fluid to be transported, reduce pre-treatment processes at a refinery and/or reduce or eliminate the need for adjusting the refinery process to compensate for the fluid.

[0069] In certain embodiments, formation conditions (for example, pressure and temperature) and/or fluid production are controlled to produce fluids with selected properties. For example, formation conditions and/or fluid production may be controlled to produce fluids with a selected API gravity and/or a selected viscosity. The selected API gravity and/or selected viscosity may be produced by combining fluids produced at different formation conditions (for example, combining fluids produced at different temperatures during the treatment as described above). As an example, formation conditions and/or fluid production may be controlled to produce fluids with an API gravity of about 19° and a viscosity of about 0.35 Pa·s (350 cp) at 5 °C.

[0070] In certain embodiments, a drive process (for example, a steam injection process such as cyclic steam injection, a steam assisted gravity drainage process (SAGD), a solvent injection process, a vapor solvent and SAGD process, or a carbon dioxide injection process) is used to treat the tar sands formation in addition to the in situ heat treatment process. In some embodiments, heaters are used to create high permeability zones (or injection zones) in the formation for the drive process. Heaters may be used to create a mobilization geometry or production network in the formation to allow fluids to flow through the formation during the drive process. For example, heaters may be used to create drainage paths between the heaters and production wells for the drive process. In some embodiments, the heaters are used to provide heat during the drive process. The amount of heat provided by the heaters may be small compared to the heat input from the drive process (for example, the heat input from steam injection).

[0071] FIG. 3 depicts a representation of an embodiment for producing hydrocarbons from a hydrocarbon containing formation (for example, a tar sands formation). Hydrocarbon layer 214 includes one or more portions with heavy hydrocarbons. Hydrocarbons may be produced from hydrocarbon layer 214 using more than one process. In certain embodiments, hydrocarbons are produced from a first portion of hydrocarbon layer 214 using a steam injection process (for example, cyclic steam injection or steam assisted gravity drainage) and a second portion of the hydrocarbon layer using an in situ heat treatment process. In the steam injection process, steam is injected into the first portion of hydrocarbon layer 214 through injection well 218. First hydrocarbons are produced from the first portion through production well 206A. The first hydrocarbons include hydrocarbons mobilized by the injection of steam. In certain embodiments, the first hydrocarbons have an API gravity of at most 15°, at most 10°, at most 8°, or at most 6°.

[0072] Heaters 216 are used to heat the second portion of hydrocarbon layer 214 to mobilization, visbreaking, and/or pyrolysis temperatures. Second hydrocarbons are produced from the second portion through production well 206B. In some embodiments, the second hydrocarbons include at least some pyrolyzed hydrocarbons. In certain embodiments, the second hydrocarbons have an API gravity of at least 15°, at least 20°, or at least 25°.

[0073] In some embodiments, the first portion of hydrocarbon layer 214 is treated using heaters after the steam injection process. Heaters may be used to increase the temperature of the first portion and/or treat the first portion using an in situ heat treatment process. Second hydrocarbons (including at least some pyrolyzed hydrocarbons) may be produced from the first portion through production well 206A.

[0074] In some embodiments, the second portion of hydrocarbon layer 214 is treated using the steam injection process before using heaters 216 to treat the second portion. The steam injection process may be used to produce some fluids (for example, first hydrocarbons or hydrocarbons mobilized by the steam injection) through production well 206B from the second portion and/or preheat the second portion before using heaters 216. In some embodiments, the steam injection process may be used after using heaters 216 to treat the first portion and/or the second portion.

[0075] Producing hydrocarbons through both processes increases the total recovery of hydrocarbons from hydrocarbon layer 214 and may be more economical than using either process alone. In some embodiments, the first portion is treated with the in situ heat treatment process after the steam injection process is completed. For example, after the steam injection process no longer produces viable amounts of hydrocarbon from the first portion, the in situ heat treatment process may be used on the first portion.

[0076] Steam is provided to injection well 218 from facility 220. Facility 220 is a steam and electricity cogeneration facility. Facility 220 may burn hydrocarbons in generators to make electricity. Facility 220 may burn gaseous and/or liquid hydrocarbons to make electricity. The electricity generated is used to provide electrical power for heaters 216. Waste heat from the generators is used to make steam. In some embodiments, some of the hydrocarbons produced from the formation are used to provide gas for heaters 216, if the heaters utilize gas to provide heat to the formation. The amount of electricity and steam generated by facility 220 may be controlled to vary the production rate and/or quality of hydrocarbons produced from the first portion and/or the second portion of hydrocarbon layer 214. The production rate and/or quality of hydrocarbons produced from the first portion and/or the second portion may be varied to produce a selected API gravity in a mixture made by blending the first hydrocarbons with the second hydrocarbons. The first hydrocarbon and the second hydrocarbons may be blended after production to produce the selected API gravity. The production from the first portion and/or the second portion may be varied in response to changes in the marketplace for either first hydrocarbons, second hydrocarbons, and/or a mixture of the first and second hydrocarbons.

[0077] First hydrocarbons produced from production well 206A and/or second hydrocarbons produced from production well 206B may be used as fuel for facility 220. In some embodiments, first hydrocarbons and/or second hydrocarbons are treated (for example, removing undesirable products) before being used as fuel for facility 220. In some embodiments, coke or other hydrocarbon residue produced or removed from the formation (for example, mined from the formation) may provide fuel for facility 220. The hydrocarbon residue may be gasified or burned in a residue burning facility before providing the hydrocarbons to facility 220. The residue burning facility may produce hydrocarbon gases (such as natural gas) and/or other products (such as carbon dioxide or syngas products). The carbon dioxide may be sequestered in the formation after treatment of the formation.

[0078] The amount of first hydrocarbons and second hydrocarbons used as fuel for facility 220 may be determined, for example, by economics for the overall process, the marketplace for either first or second hydrocarbons, availability of treatment facilities for either first or second hydrocarbons, and/or transportation facilities available for either first or second hydrocarbons. In some embodiments, most or all the hydrocarbon gas produced from hydrocarbon layer 214 is used as fuel for facility 220. Burning all the hydrocarbon gas in facility 220 eliminates the need for treatment and/or transportation of gases produced from hydrocarbon layer 214.

[0079] The produced first hydrocarbons and the second hydrocarbons may be treated and/or blended in facility 222. In some embodiments, the first and second hydrocarbons are blended to make a mixture that is transportable through a pipeline. In some embodiments, the first and second hydrocarbons are blended to make a mixture that is useable as a feedstock for a refinery. The amount of first and second hydrocarbons produced may be varied based on changes in the requirements for treatment and/or blending of the hydrocarbons. In some embodiments, treated hydrocarbons are used in facility 220.

[0080] In some embodiments, the steam injection process and the in situ heat treatment process (for example, the in situ conversion process) are used synergistically in different layers (for example, vertically displaced layers) in the formation. For example, in a karsted formation, different zones or layers in the formation may have different oil saturations, water saturations, porosities, and/or permeabilities. Some layers may have good steam injectivities while others have near zero steam injectivity. The steam injectivity may depend on the water saturation of the zone and the permeability. Thus, varying the use of the steam injection process and the in situ heat treatment process in these layers may be economically advantageous by, for example, producing more hydrocarbons with less energy input into the formation. The steam injection process may include steam drive, cyclic steam injection, SAGD, or other process of steam injection into the formation.

[0081] FIG. 4 depicts a representation of an embodiment for producing hydrocarbons from multiple layers in a tar sands formation. Hydrocarbon layers 214A,B,C include one or more portions with heavy hydrocarbons. Hydrocarbon layers 214A,B,C may have different oil saturations, water saturations, porosities, and/or permeabilities. In one embodiment, hydrocarbon layers 214A,C have lower oil saturations, higher water saturations, and lower porosities than hydrocarbon layer 214B. The steam injection process may be used in hydrocarbon layers 214A,C using injection wells 218A,C and production wells 206A,C. The in situ heat treatment process may be used in hydrocarbon layer 214B using heaters 216 and production well 206B. In some embodiments, the in situ heat treatment process is used in hydrocarbon layer 214B, which has high oil saturation and low steam injectivity. After in situ heat treatment of hydrocarbon layer 214B, the layer may have steam injectivity. The hydrocarbon layer 214B may be treated using the steam injection process for a selected time (for example, one year, two years, three years, or longer).

[0082] Injecting steam into hydrocarbon layers 214A,C above and below hydrocarbon layer 214B may increase the efficiency of producing hydrocarbons from the formation. Steam injection in hydrocarbon layers 214A,C lowers the viscosity and increases the pressures in these layers so that hydrocarbons move into hydrocarbon layer 214B. Heat from hydrocarbon layer 214B may conduct and/or convect into hydrocarbon layers 214A,C and preheat these layers to lower the oil viscosity and/or increase the steam injectivity in hydrocarbon layers 214A,C. Additionally, some steam may rise from hydrocarbon layer 214C into hydrocarbon layer 214B. This steam may provide additional heat and increased mobilization in hydrocarbon layer 214B. The steam injection process and/or the in situ heat treatment process may be used (for example, varied) as described above for the embodiment depicted in FIG. 3. Hydrocarbons produced from any of hydrocarbon layers 214A,B,C may be used and/or processed in facility 220 and/or facility 222, as described above for the embodiment depicted in FIG. 3.

[0083] In some embodiments, impermeable shale layers exist between hydrocarbon layer 214B and hydrocarbon layers 214A,C. Using the in situ heat treatment process on hydrocarbon layer 214B may desiccate the shale layers and increase the permeability of the shale layers to allow fluid to flow through the shale layers. The increased permeability in the shale layers allows mobilized hydrocarbons to flow from hydrocarbon layer 214A into hydrocarbon layer 214B. These hydrocarbons may be upgraded and produced in hydrocarbon layer 214B.

[0084] 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.

CLAIMS

1. A method for treating a tar sands formation, comprising:

providing a drive fluid to a first hydrocarbon containing layer of the formation to mobilize at least some hydrocarbons in the first layer;

allowing at least some of the mobilized hydrocarbons to flow into a second hydrocarbon containing layer of the formation;

providing heat to the second layer from one or more heaters located in the second layer; and

producing at least some hydrocarbons from the second layer of the formation.

2. The method of claim 1, further comprising providing the drive fluid to a third hydrocarbon containing layer of the formation to mobilize at least some hydrocarbons in the third layer.

3. The method of any of claims 1 or 2, further comprising providing the drive fluid to a third hydrocarbon containing layer of the formation to mobilize at least some hydrocarbons in the third layer, and allowing at least some of the mobilized hydrocarbons from the third layer to flow into the second layer.

4. The method of claim 1, wherein the first layer is above the second layer.

5. The method of claim 1, wherein the first layer is below the second layer.

6. The method of claim 1, wherein the first layer has a lower initial oil saturation than the second layer.

7. The method of claim 1, wherein the first layer has a higher initial water saturation than the second layer.

8. The method of claim 1, wherein the first layer has a lower initial porosity than the second layer.

9. The method of claim 1, wherein the first layer has a higher initial steam injectivity than the second layer.

10. The method of claim 1, further comprising increasing the steam injectivity of the second layer with the heat provided by the one or more heaters.

11. The method of claim 1, further comprising providing the drive fluid to the second layer after increasing the steam injectivity of the second layer with the heat provided by the one or more heaters.

12. The method of claim 1, further comprising producing hydrocarbons from the first layer.

13. The method of claim 1, further comprising using the produced hydrocarbons in a steam and electricity generation facility, wherein the facility provides steam as the drive fluid to the first layer of the formation, and electricity for at least some of the heaters in the second layer.

14. The method of claim 1, wherein the first layer and the second layer are separated by a substantially impermeable shale layer that inhibits the flow of hydrocarbons between the first and second layers.

15. The method of claim 14, further comprising increasing the permeability of the shale layer with the heat provided to the second layer such that hydrocarbons are allowed to flow between the first and second layers.

16. The method of claim 1, further comprising maintaining a pressure in the formation below a selected pressure.

17. The method of claim 16, wherein the selected pressure is the fracture pressure of the formation.

18. The method of any of claims 16 or 17, wherein the selected pressure is between about 1000 kPa and about 15000 kPa.

19. The method of claim 16, wherein the selected pressure is a pressure below which substantial hydrocarbon coking in the formation occurs when the average temperature in the formation is less than 300 °C.

20. The method of claim 19, wherein the selected pressure is between about 100 kPa and about 1000 kPa.

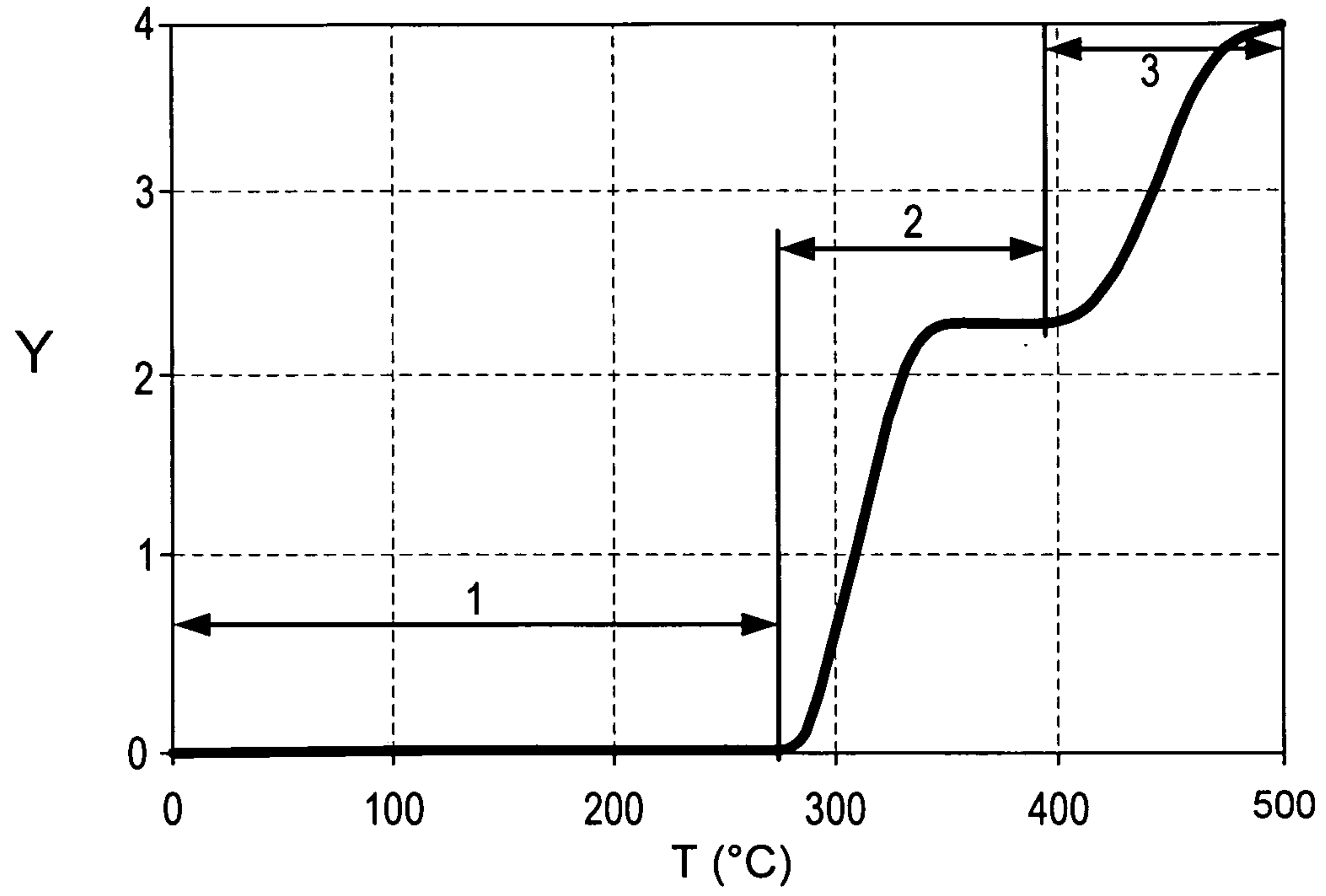
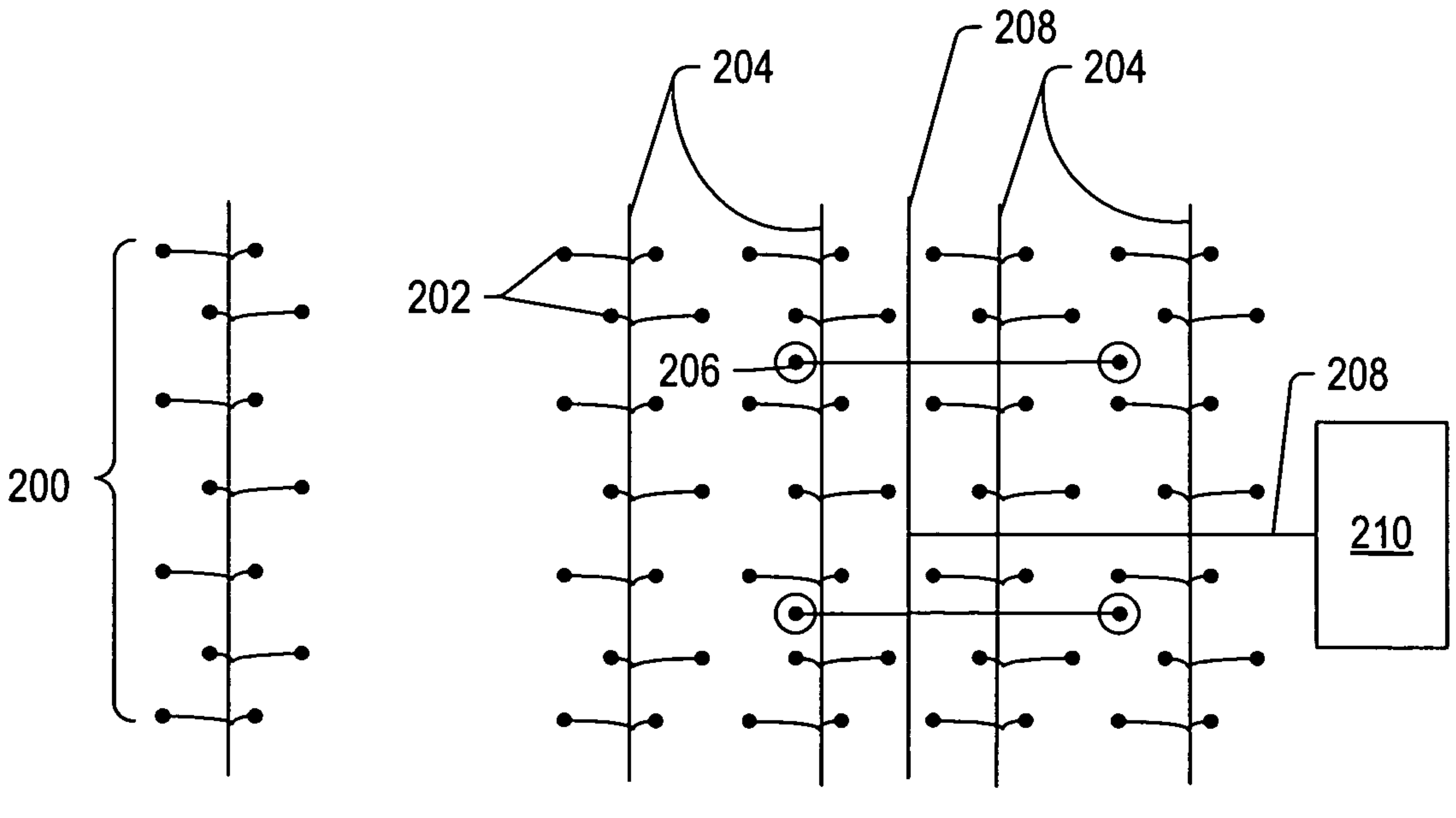

Y
4
3
2
1
0
0
100
200
300
400
500
T (°C)
1
2
3

FIG. 1


200
202
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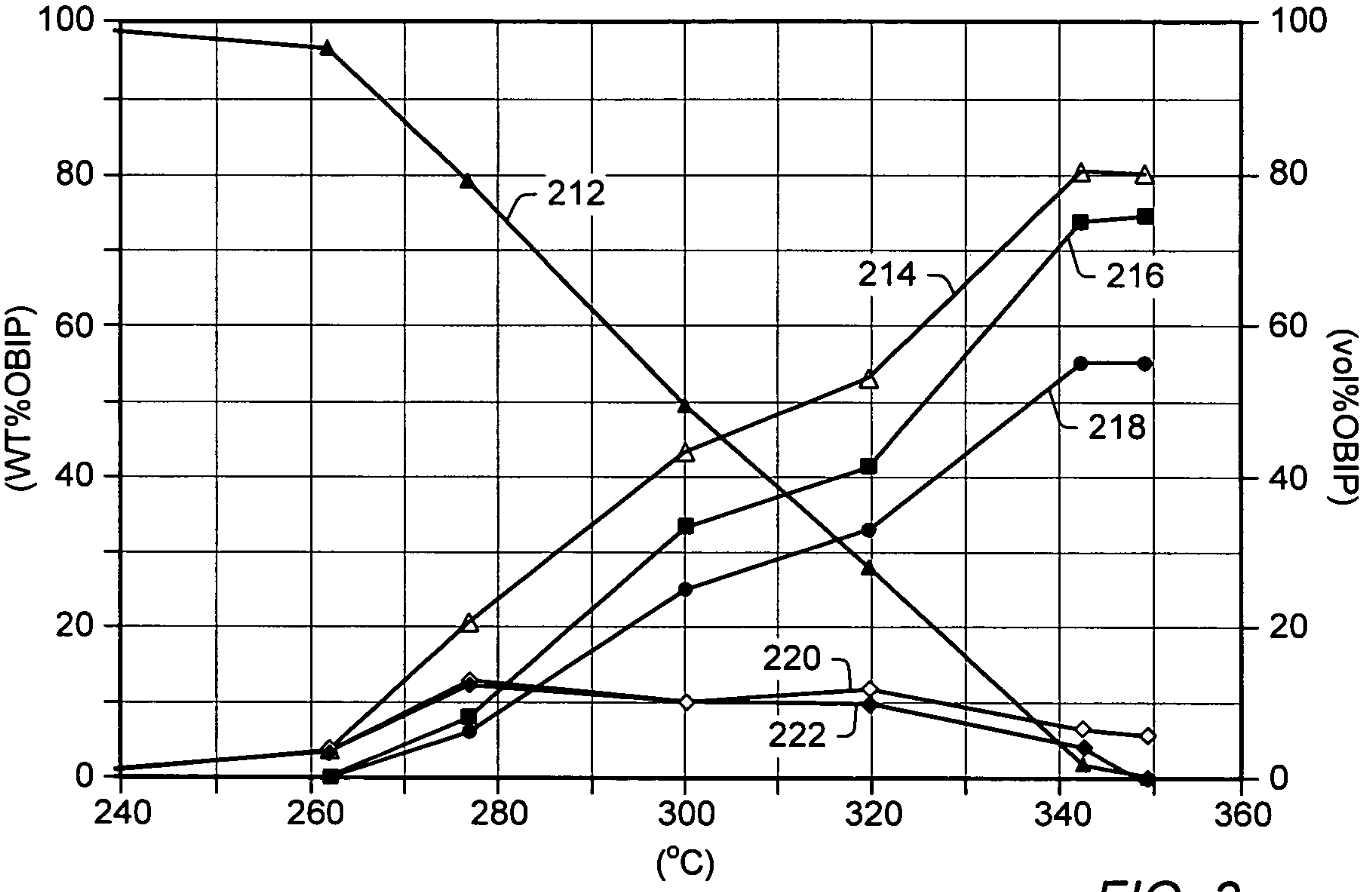
204
206
208
208
210

FIG. 2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60
40
20
0
(WT%OBIP)
(vol%OBIP)
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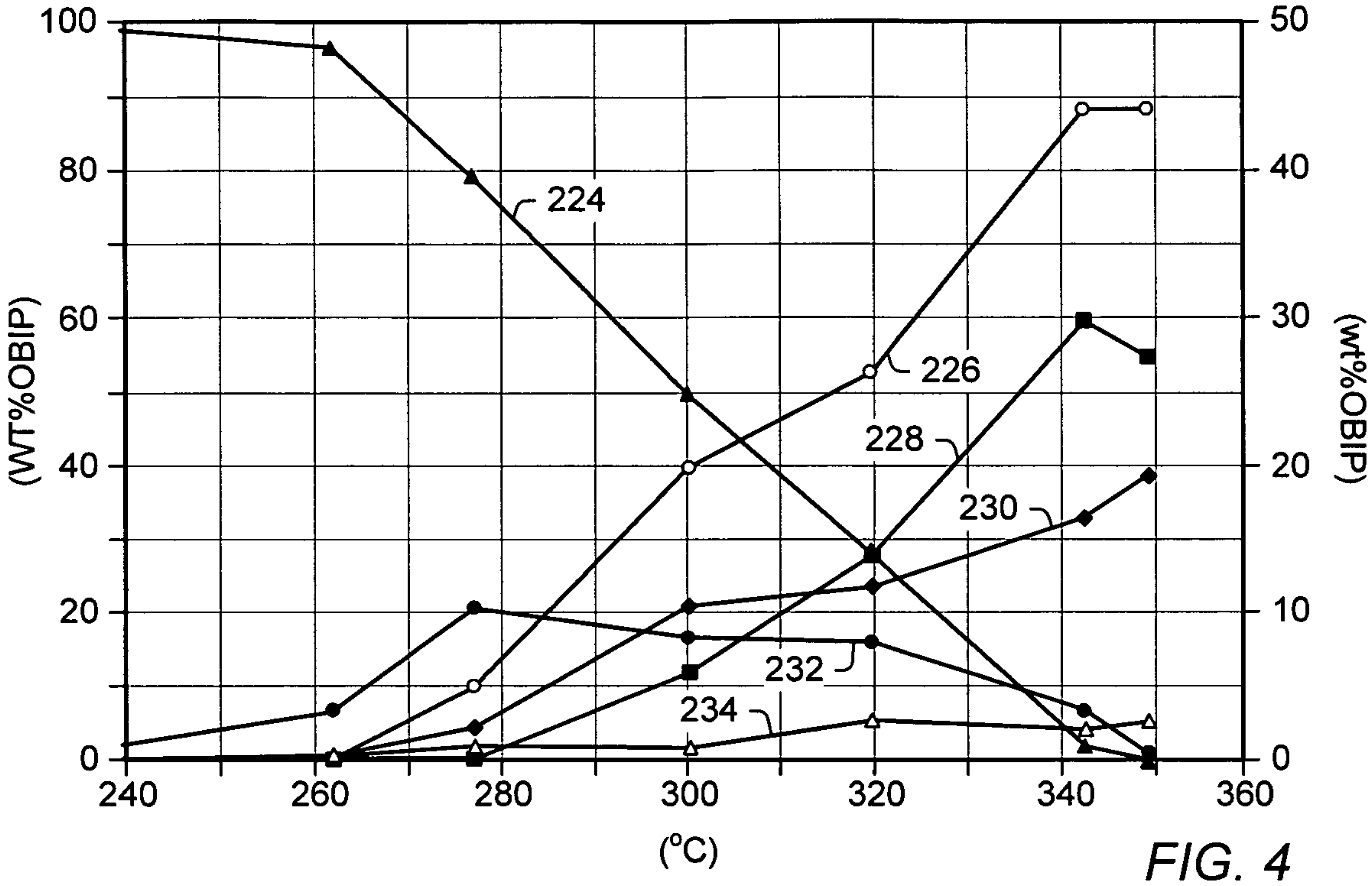
260
280
300
320
340
360
(°C)
212
214
216
218
220
222

FIG. 3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40
20
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(WT%OBIP)
50
40
30
20
10
0
(wt%OBIP)
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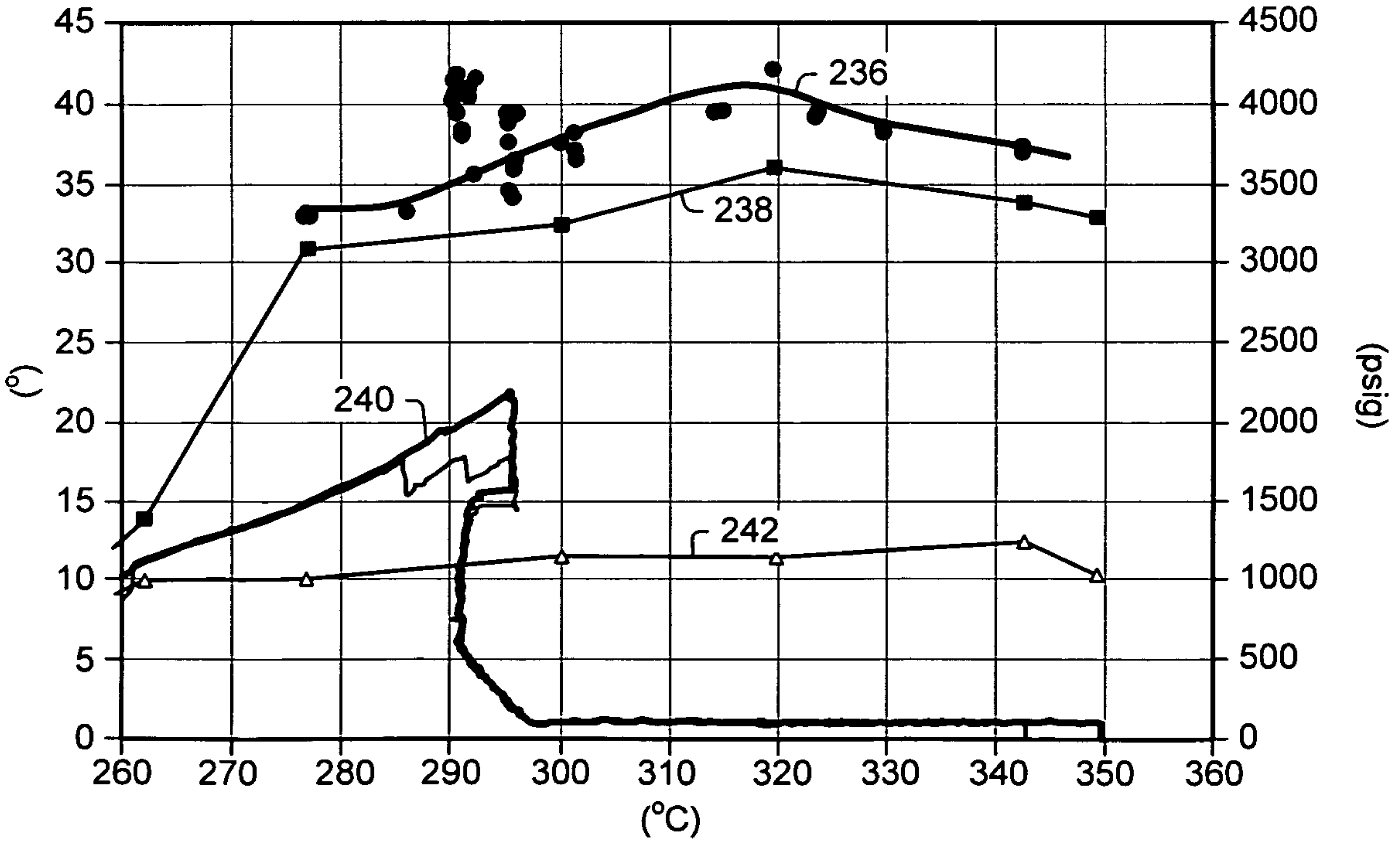
280
300
320
340
360
(°C)
224
226
228
230
232
234

FIG. 4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40
35
30
25
20
15
10
5
0
(°)
4500
4000
3500
3000
2500
2000
1500
1000
500
0
(psig)
260
270
280
290
300
310
320
330
340
350
360
(°C)
236
238
240
242

FIG. 5

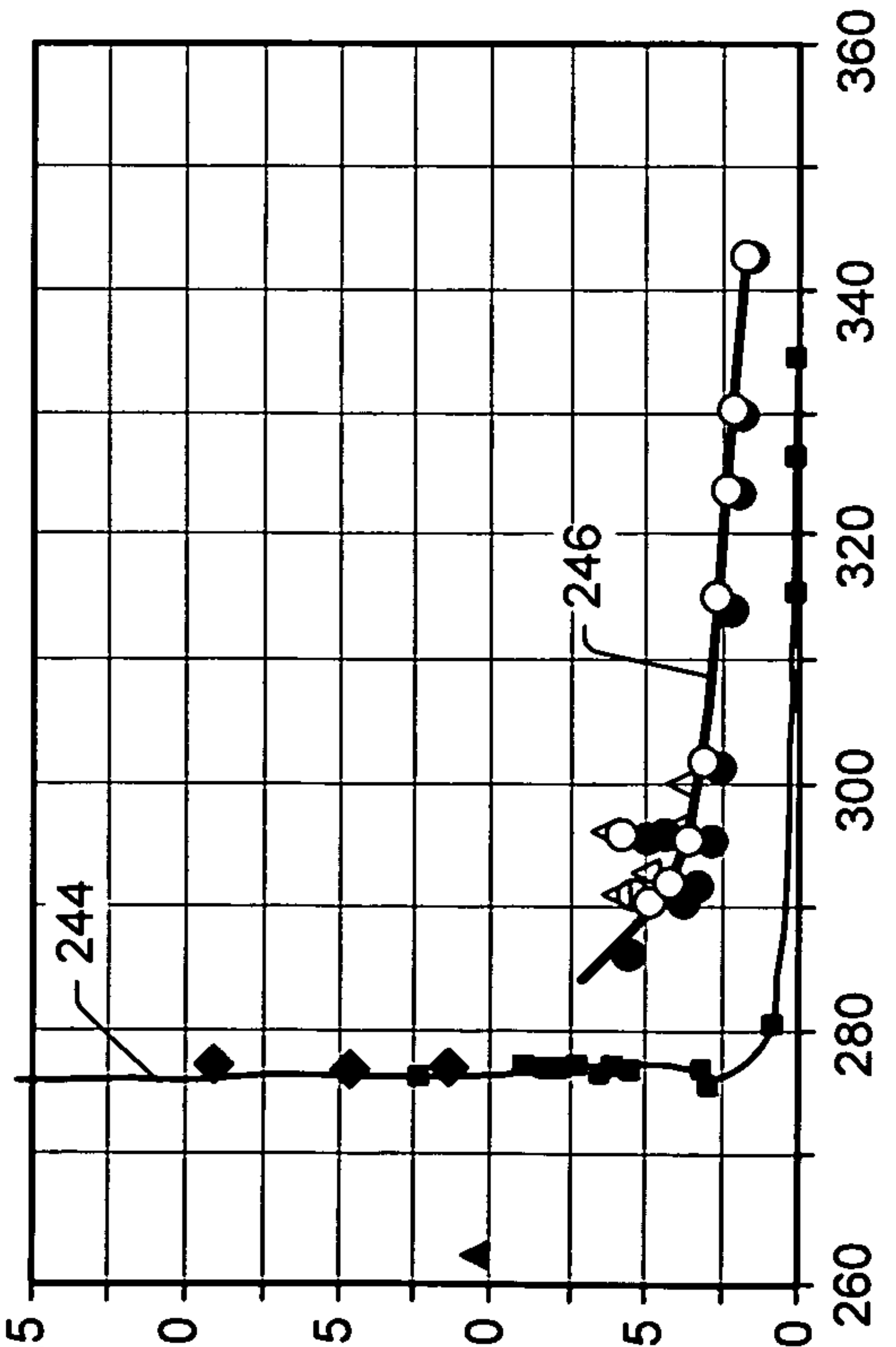


FIG. 6A

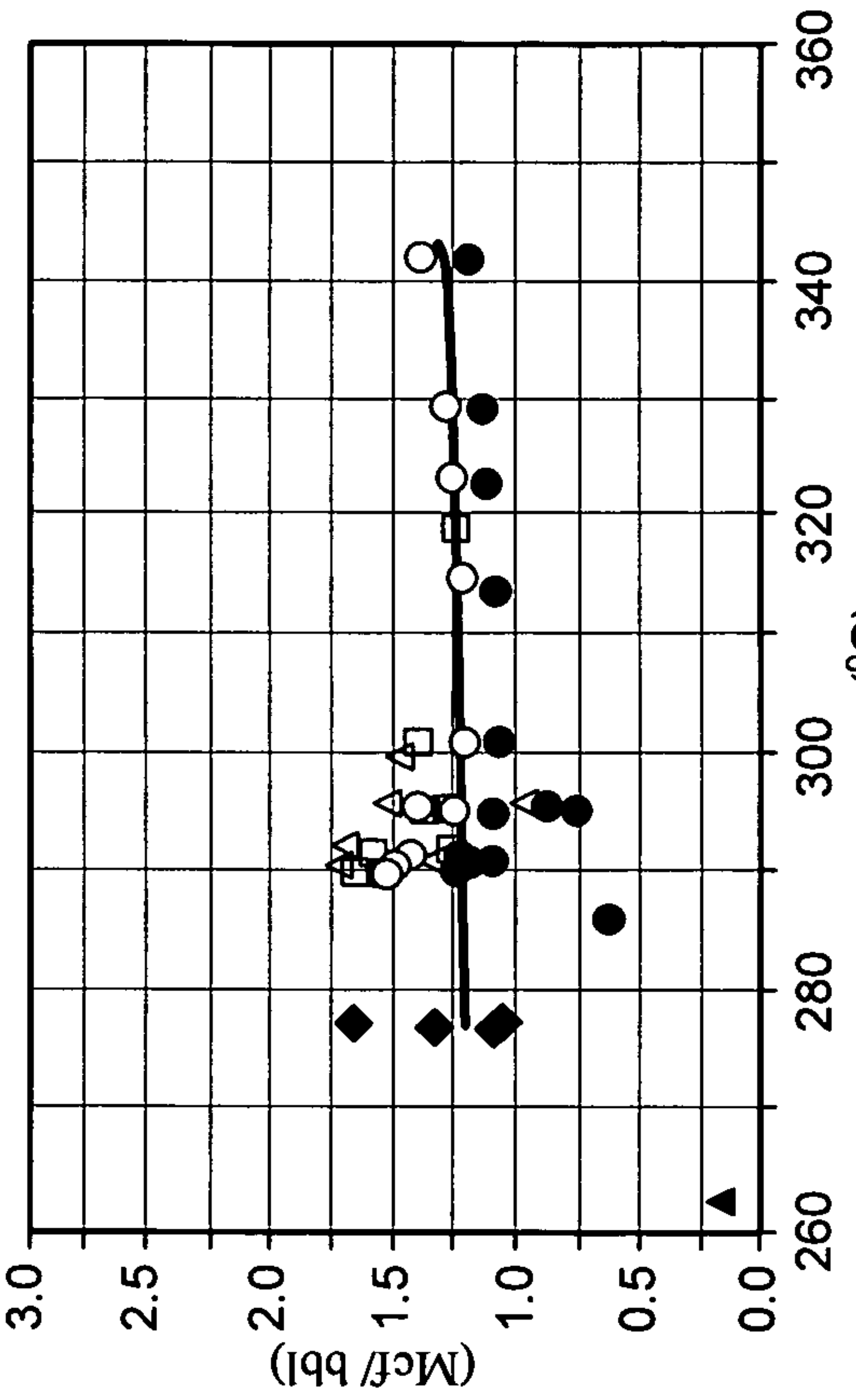


FIG. 6B

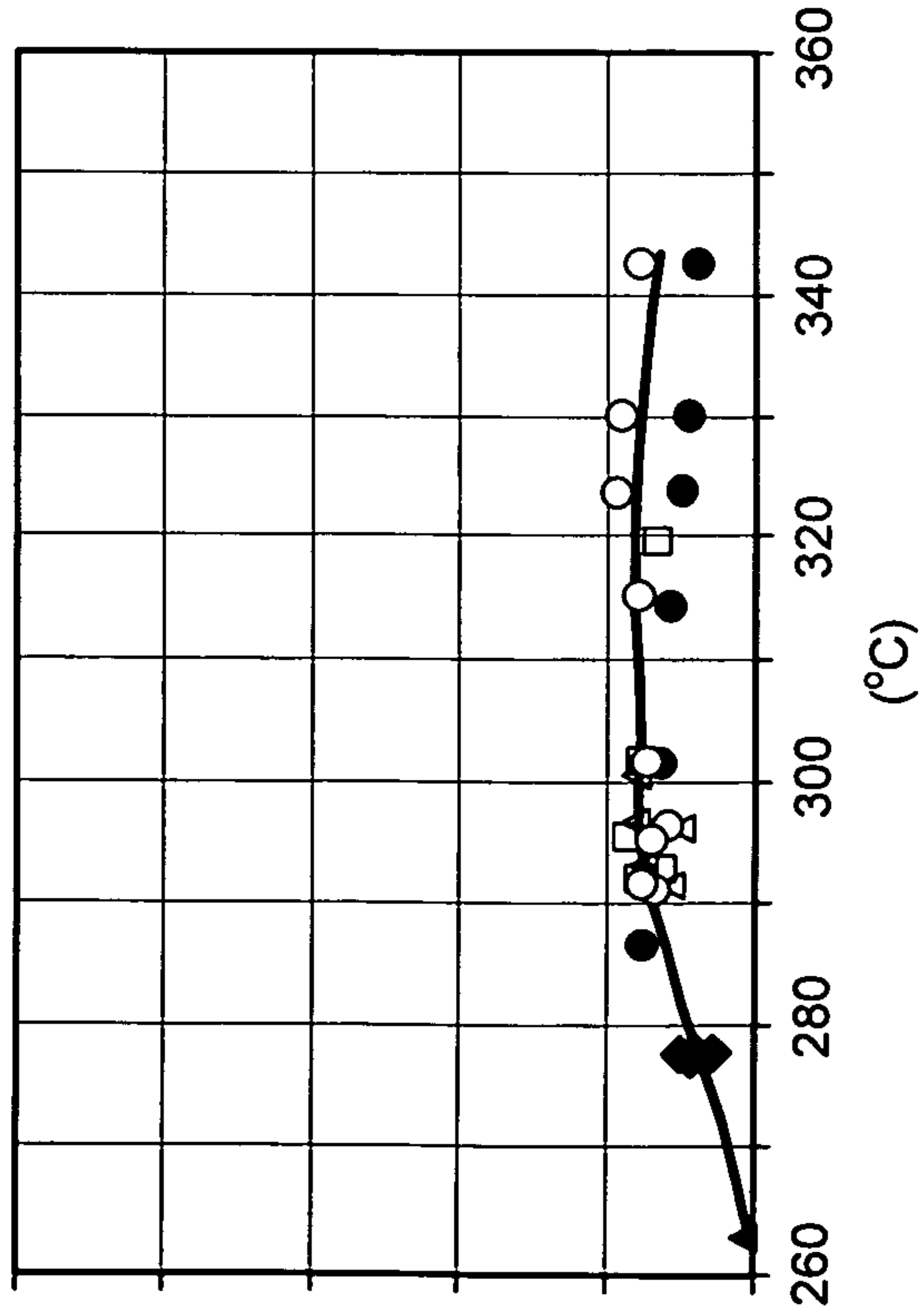


FIG. 6C

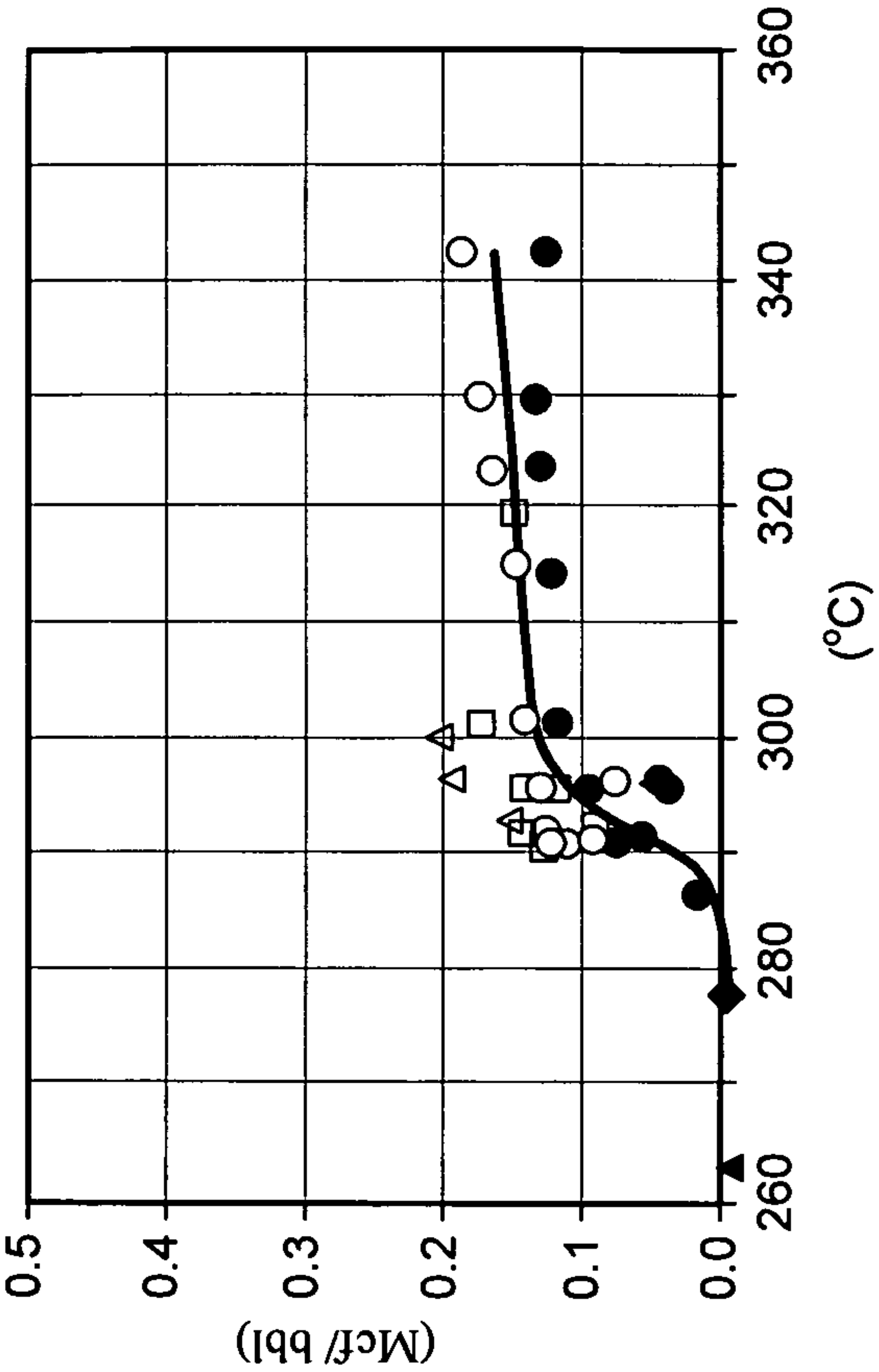
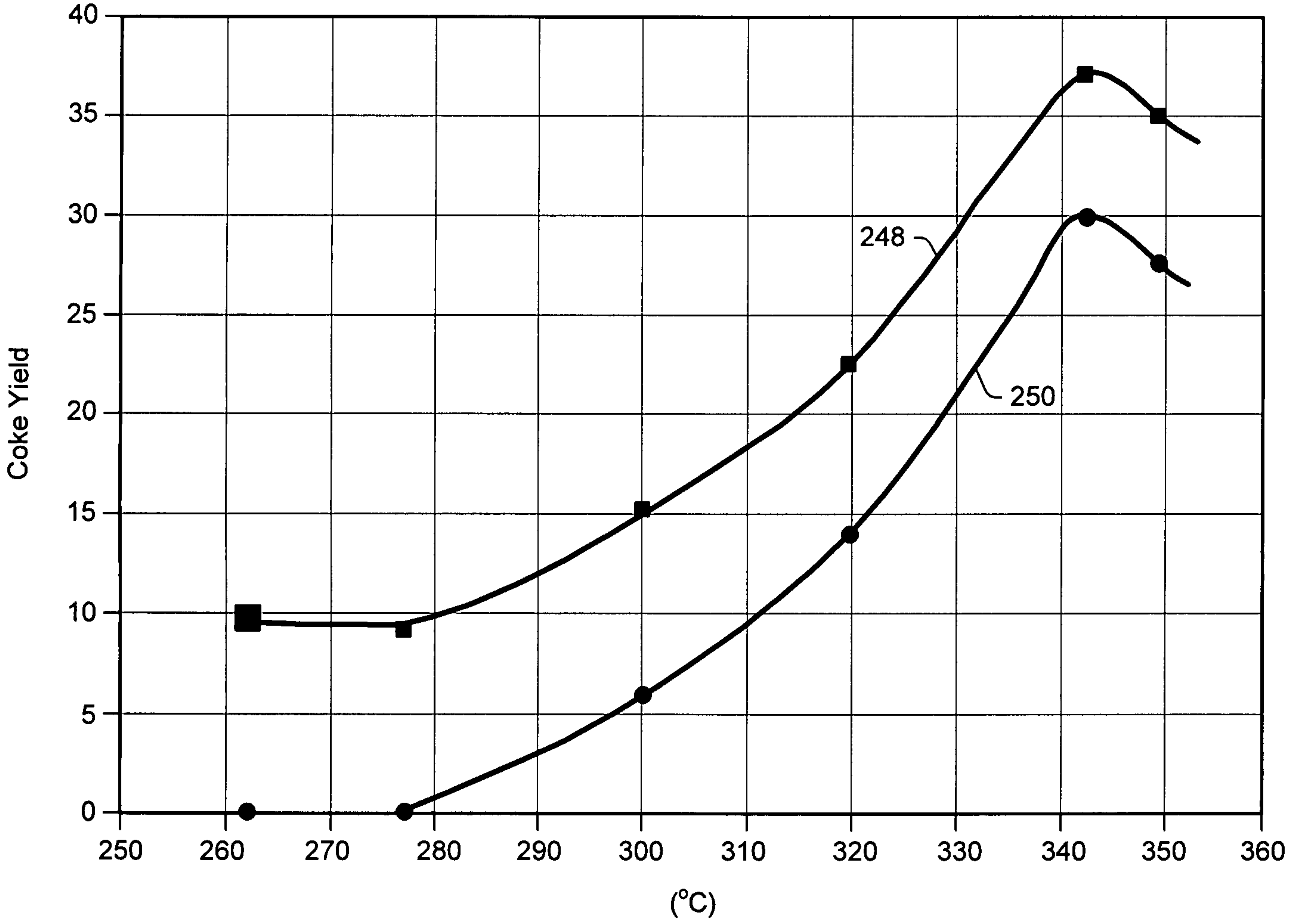


FIG. 6D


Coke Yield
40
35
30
25
20
15
10
5
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250
260
270
280
290
300
310
320
330
340
350
360
(°C)
248
250

FIG. 7

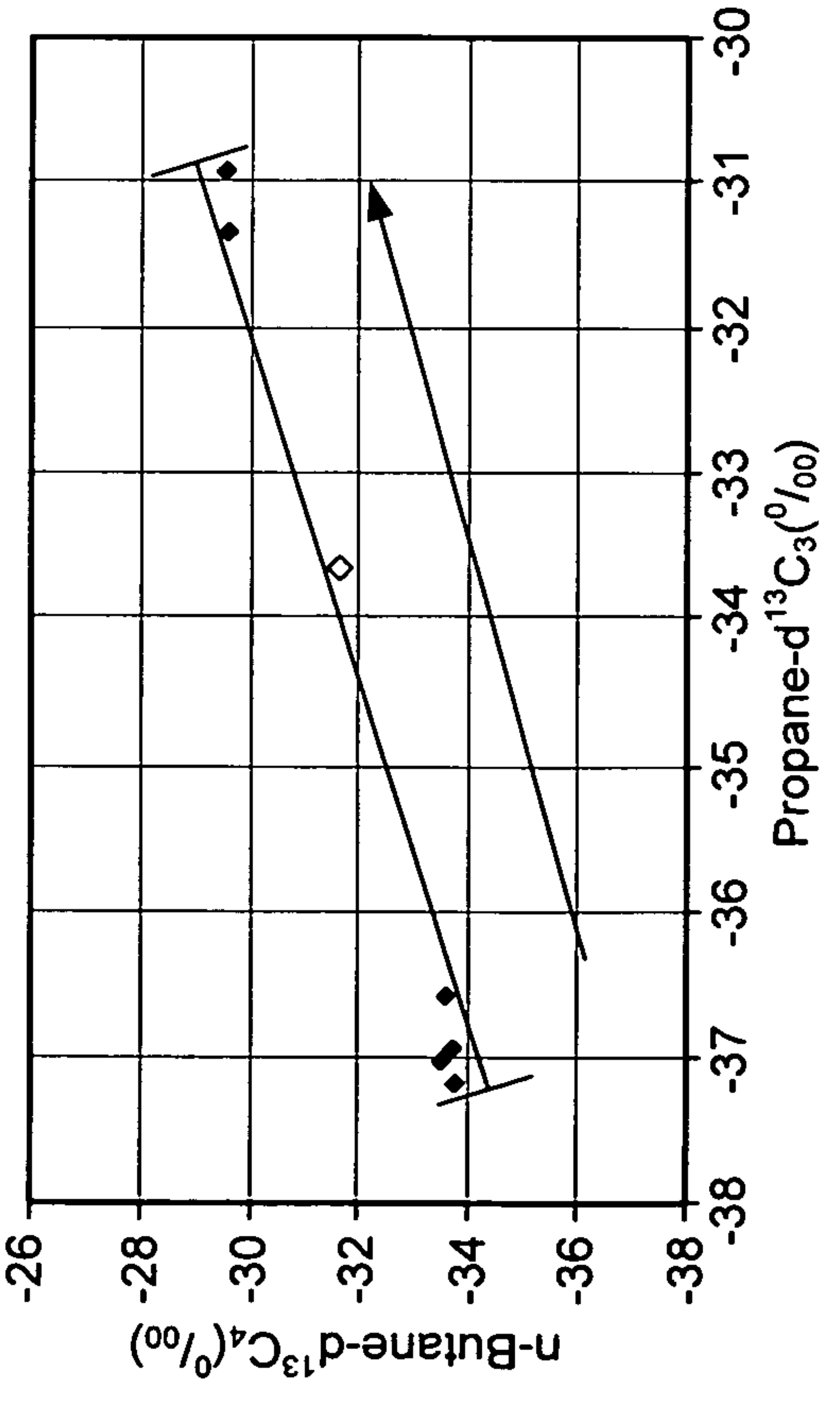

FIG. 8A

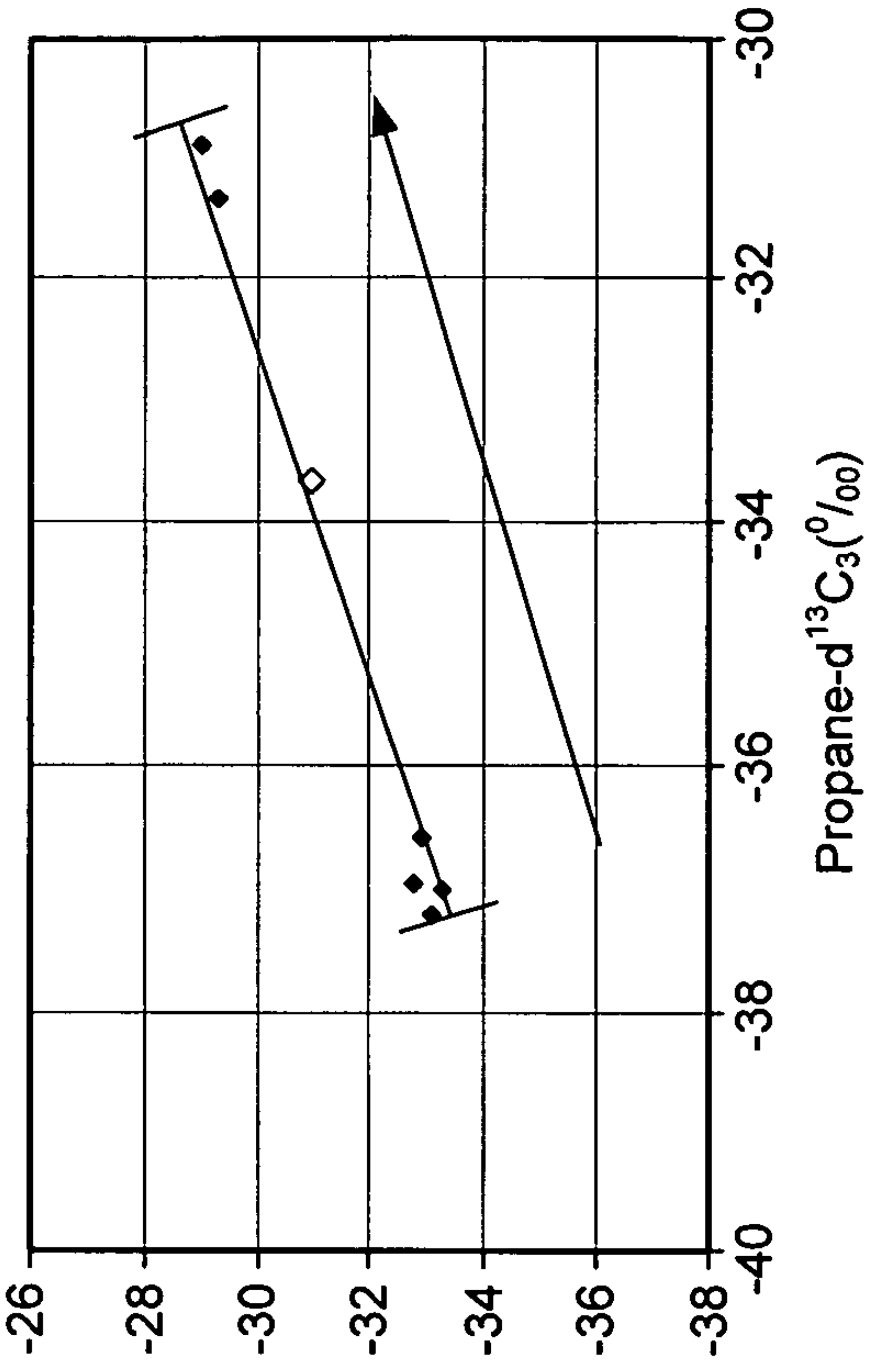

FIG. 8B

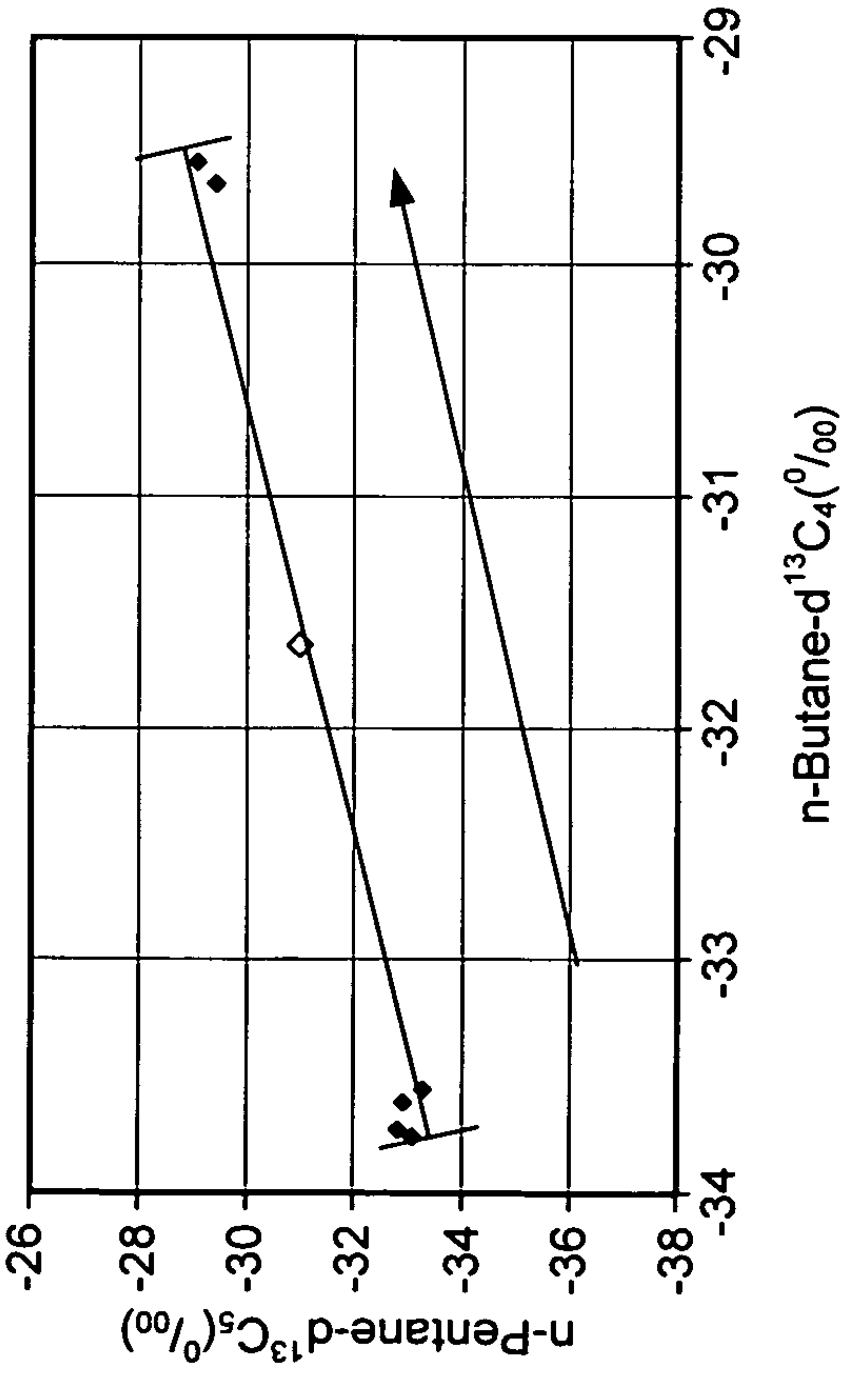

FIG. 8C

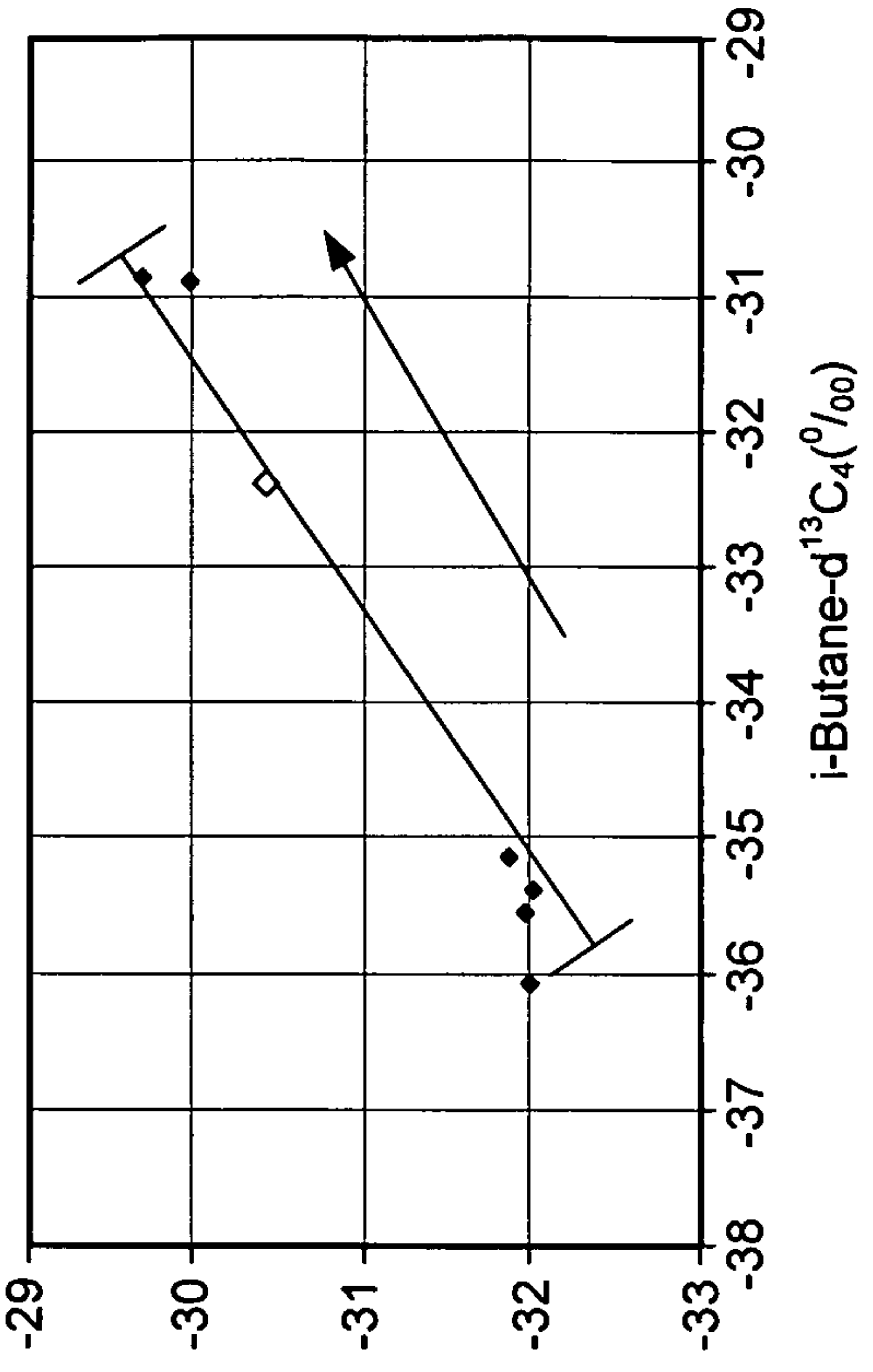

FIG. 8D

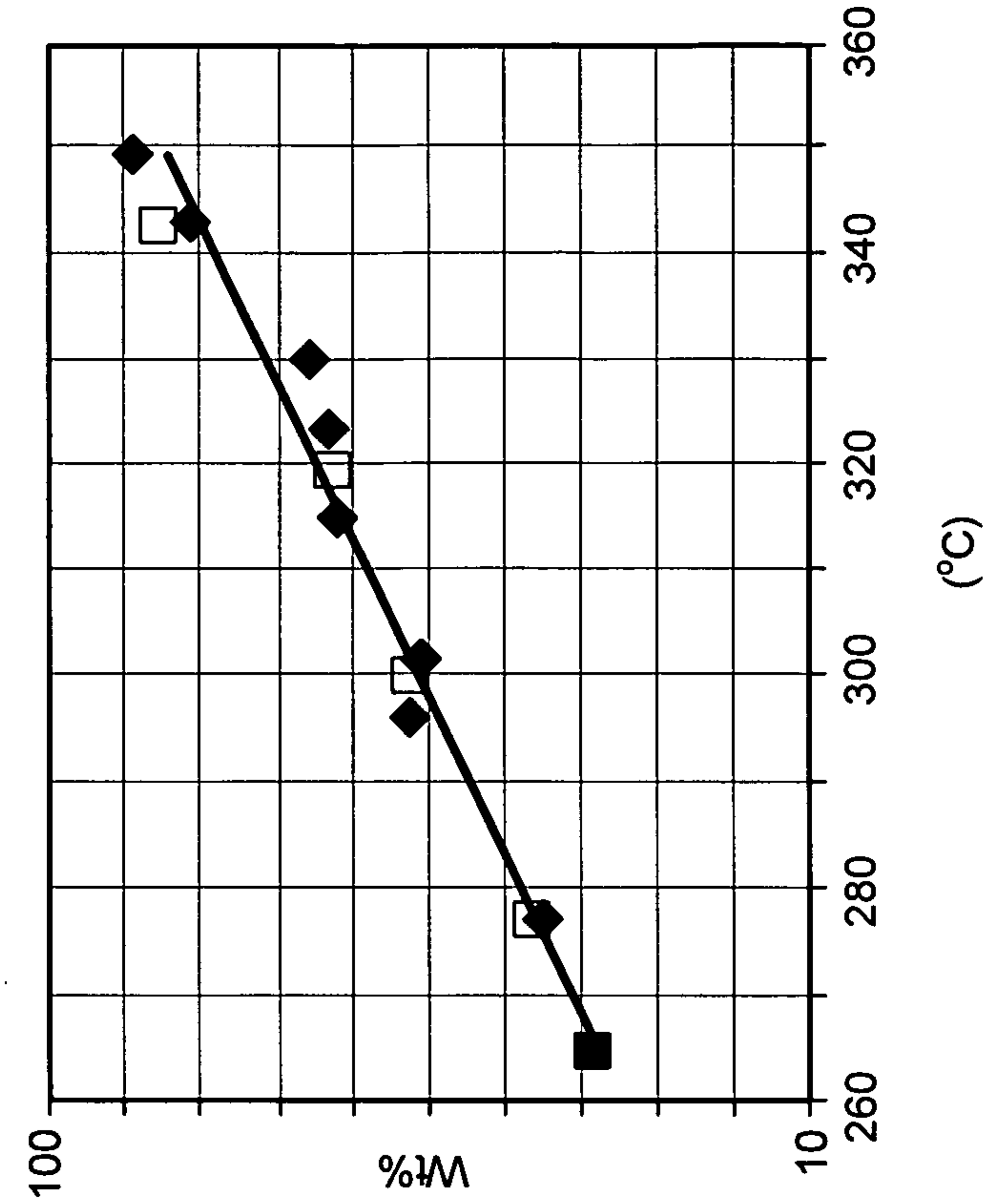
100
10
Wt%
260
280
300
320
340
360
(°C)

FIG. 10

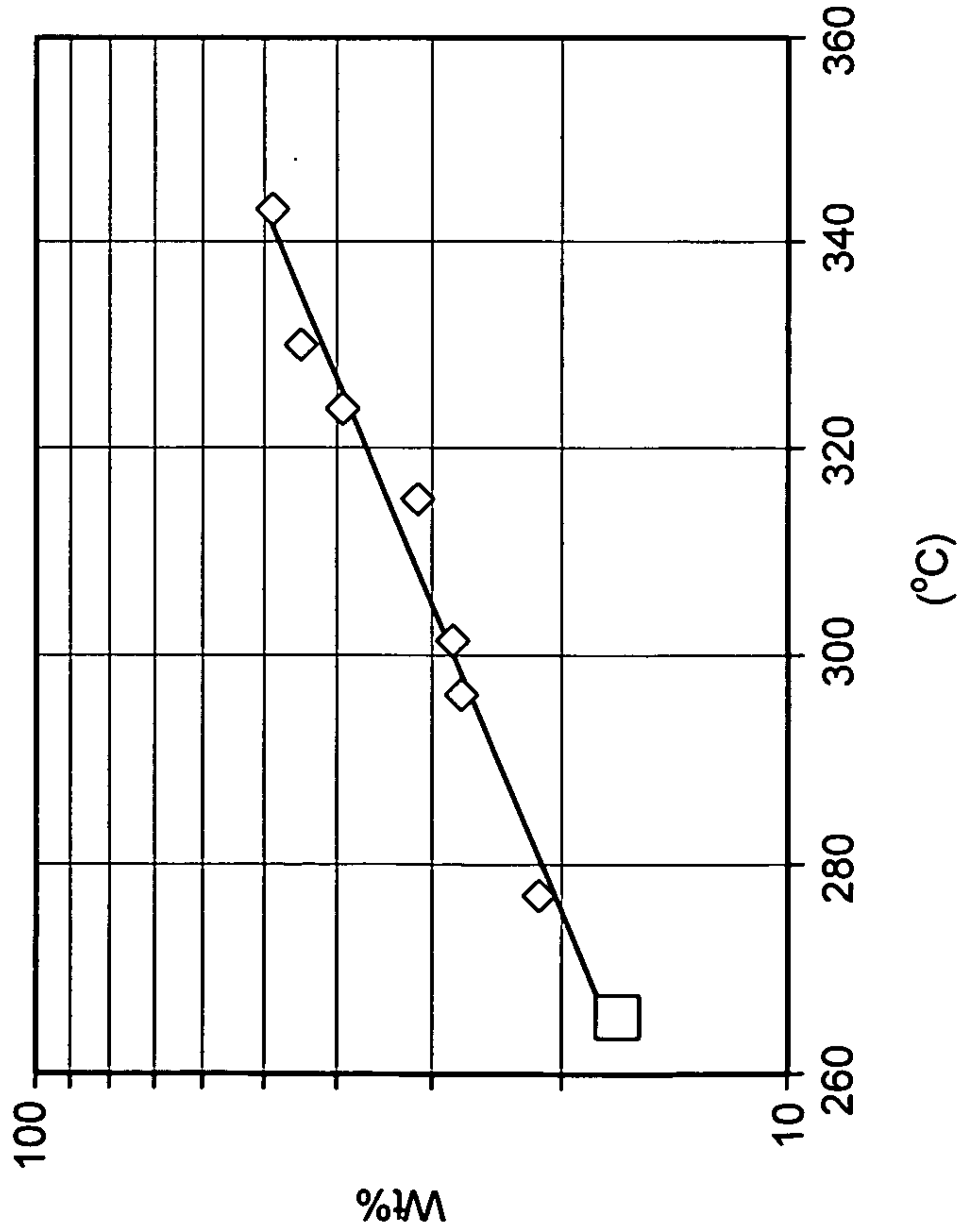
100
10
Wt%
260
280
300
320
340
360
(°C)

FIG. 9

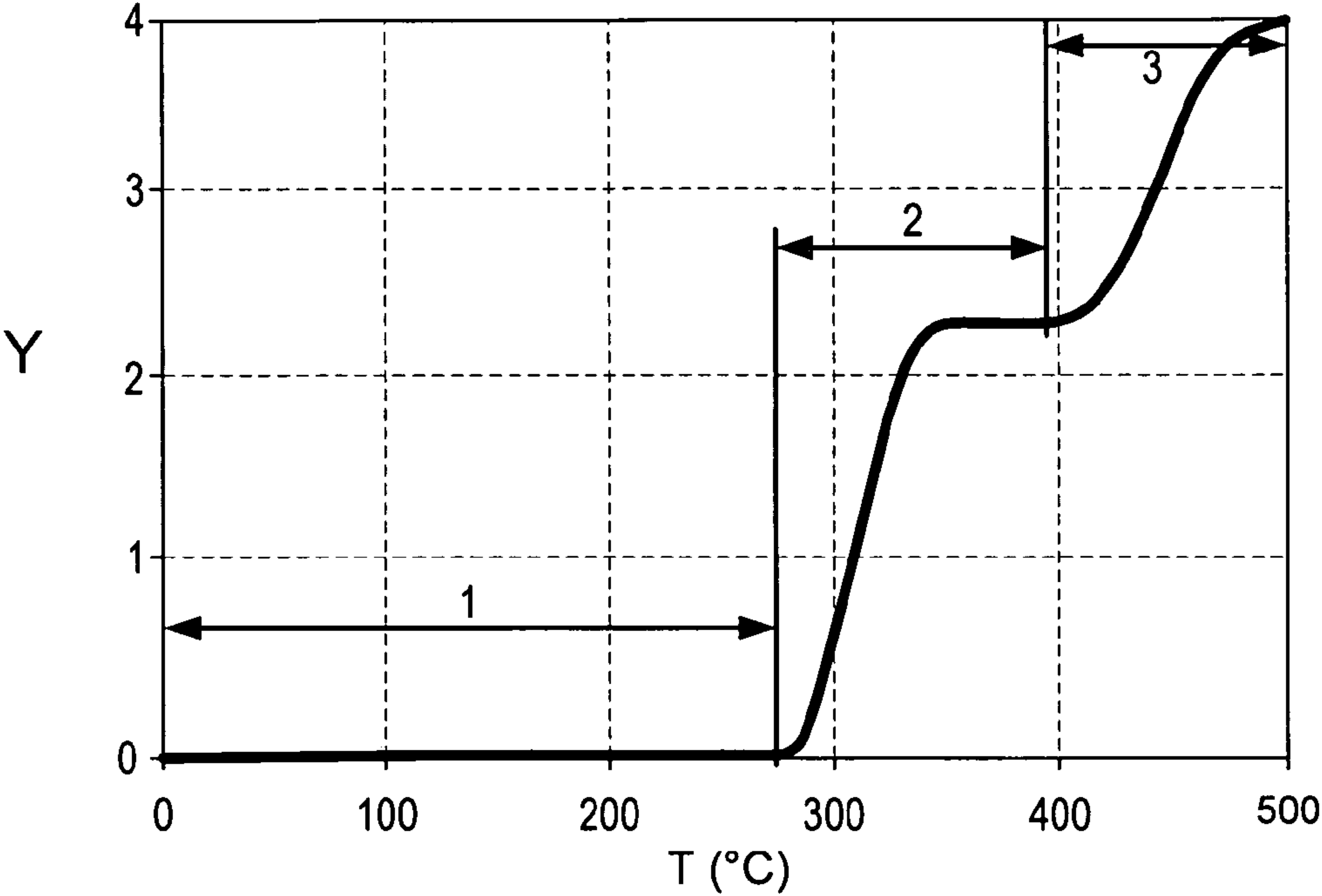

FIG. 1