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Canadian Intellectual Property Office
An agency of Industry Canada

CA 2888892 A1 2015/10/22

(21) 2 888 892

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(22) Date de dépôt/Filing Date: 2015/04/22

(41) Mise à la disp. pub./Open to Public Insp.: 2015/10/22

(30) Priorité/Priority: 2014/04/22 (US61/982,772)

(51) Cl.Int./Int.Cl. *E21B 43/24* (2006.01),
E21B 43/14 (2006.01)

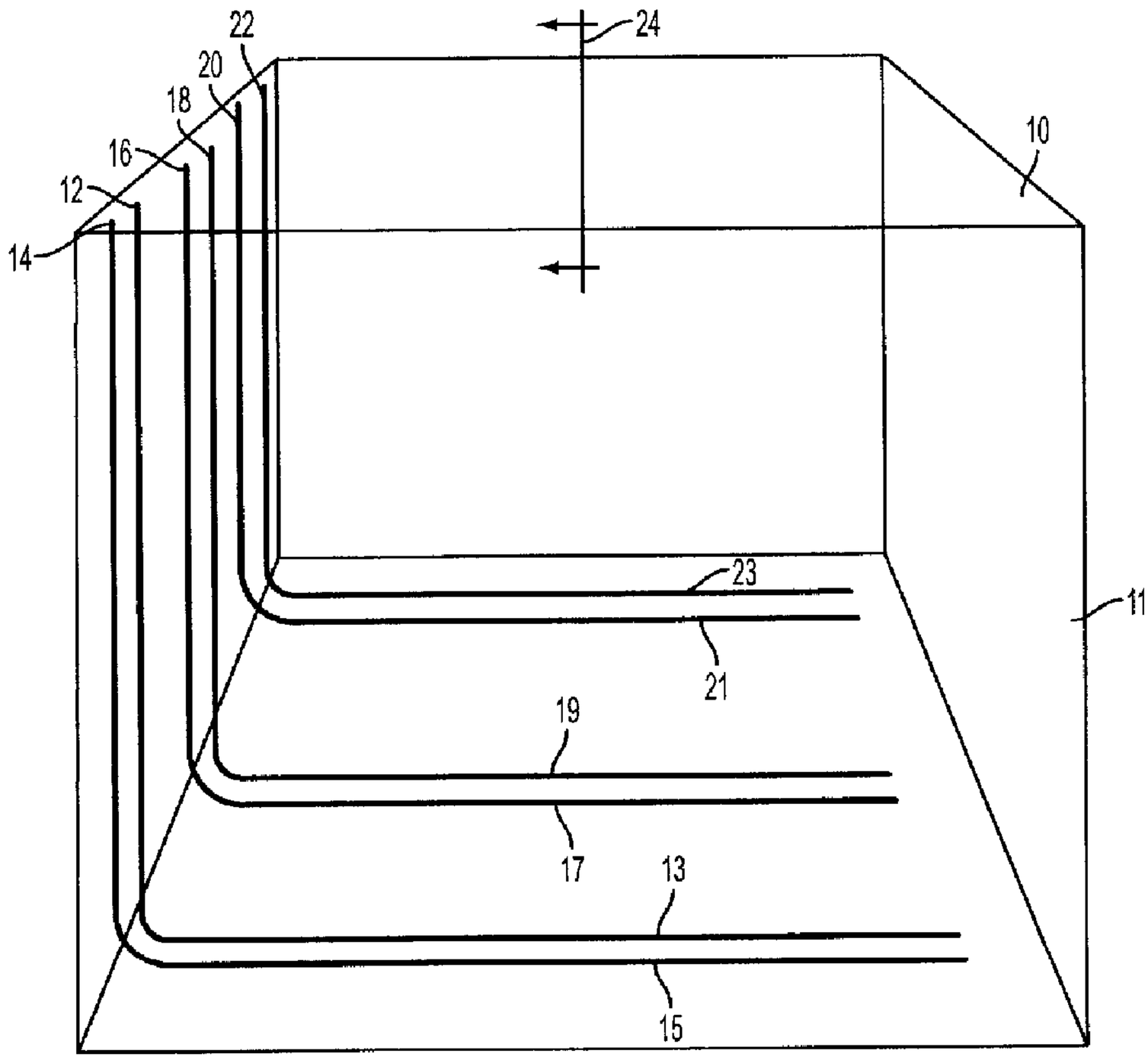
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(54) Titre : GESTION DE GAZ NON CONDENSABLES DANS LE DRAINAGE PAR GRAVITE AU MOYEN DE VAPEUR

(54) Title: NON CONDENSING GAS MANAGEMENT IN SAGD



(57) Abrégé/Abstract:
The invention provides processes for producing mobilized bitumen and non-condensing gases from a radially expanding steam chamber in a SAGD process. Production of non-condensing gases is facilitated by systems for providing an axial pressure gradient along the longitudinal axis of the steam chamber, so that the non- condensing gas flows in the axial dimension of the steam chamber in a convective flow motivated by the axial pressure gradient.

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ABSTRACT

The invention provides processes for producing mobilized bitumen and non-condensing gases from a radially expanding steam chamber in a SAGD process. Production of non-condensing gases is facilitated by systems for providing an axial pressure gradient along the longitudinal axis of the steam chamber, so that the non-condensing gas flows in the axial dimension of the steam chamber in a convective flow motivated by the axial pressure gradient.

NON CONDENSING GAS MANAGEMENT IN SAGD

FIELD OF THE INVENTION

[0001] The invention is in the field of hydrocarbon reservoir engineering, particularly thermal recovery processes such as steam assisted gravity drainage (SAGD) systems in heavy oil reservoirs.

BACKGROUND OF THE INVENTION

[0002] Some subterranean deposits of viscous hydrocarbons can be extracted in situ by lowering the viscosity of the petroleum to mobilize it so that it can be moved to, and recovered from, a production well. Reservoirs of such deposits may be referred to as reservoirs of heavy hydrocarbon, heavy oil, bitumen, tar sands, or oil sands. The in situ processes for recovering oil from oil sands typically involve the use of multiple wells drilled into the reservoir, and are assisted or aided by injecting a heated fluid such as steam into the reservoir formation from an injection well, for example, in steam-assisted gravity drainage (SAGD) processes.

[0003] A typical SAGD process is disclosed in Canadian Patent No. 1,130,201 issued on 24 August 1982, in which two wells are drilled into the deposit, one for injection of steam and one for production of oil and water. Steam is injected via the injection well to heat the formation. The steam condenses and gives up its latent heat to the formation, heating a layer of viscous hydrocarbons. The viscous hydrocarbons are thereby mobilized, and drain by gravity toward the production well with an aqueous condensate. In this way, the injected steam initially mobilises the in-place hydrocarbon to create a “steam chamber” in the reservoir around and above the horizontal injection well. The term “steam chamber” accordingly refers to the volume of the reservoir which is saturated with injected steam and from which mobilized oil has at least partially drained. Mobilized viscous hydrocarbons are recovered continuously through the production well. The conditions of steam injection and of hydrocarbon production may be modulated to control the growth of the steam chamber, to ensure that the production well remains located at the bottom of the steam chamber in an appropriate position to collect mobilized hydrocarbons.

[0004] The start-up stage of the SAGD process establishes thermal or hydraulic communication, or both, between the injection and production wells. At initial reservoir conditions, there is typically negligible fluid mobility between wells due to high bitumen viscosity. Communication is achieved when bitumen between the injector and producer is mobilized to allow for bitumen production. A conventional start-up process involves establishing interwell communication by simultaneously circulating steam through each injector well and producer well. High-temperature steam flows through a tubing string that extends to the toe of each horizontal well. The steam condenses in the well, releasing heat and resulting in a liquid water phase which flows back up the casing-tubing annulus. Alternative start-up techniques involve creating a high mobility inter-well path by the use of solvents or by application of pressures so as to dilate the reservoir sand matrix.

[0005] In the ramp-up stage of the SAGD process, after communication has been established between the injection and production wells during start-up (usually over a limited section of the well pair length), production begins from the production well. Steam is continuously injected into the injection well (usually at constant pressure) while mobilized bitumen and water are continuously removed from the production well (usually at constant temperature). During this period the zone of communication between the wells is expanded axially along the full well pair length and the steam chamber grows vertically up to the top of the reservoir. The reservoir top may be a thick shale (overburden) or some lower permeability facies that causes the steam chamber to stop rising. When the interwell region over the entire length of the well pair has been heated and the steam chamber that develops has reached the reservoir top, the bitumen production rate typically peaks and begins to decline while the steam injection rate reaches a maximum and levels off.

[0006] In conventional SAGD, after ramp-up, in an operational phase of production, the steam chamber has generally achieved full height (although it is typically still rising slowly through or spreading around lower permeability zones in some locations) and lateral or radial growth of the steam chamber along the longitudinal axis of the well pair

becomes the dominant mechanism for recovering bitumen. Typically steam injection at the injector well is controlled so as to maintain a target steam chamber pressure during this phase. As the emulsion drains to the production well, fluid withdrawal rates are controlled to ensure the well remains submerged in bitumen and steam condensate. Submergence prevents the steam that overlies the liquid zone from breaking through to the production well, which can short-circuit the SAGD process and potentially damage the wellbore. In certain instance submergence is not achieved along the entire of length of the well bore. This may be due to reservoir heterogeneity, such as pay, permeability or saturation differences, and well bore hydraulic issues imposed by the trajectory or completion design. Exposing part of the production well to the steam chamber could allow for NCG gas production.

[0007] A concomitant of a thermal recovery process applied to an oil sand is that non-condensing gases (NCGs) are evolved and created. In a typical implementation of SADG, there are a number of sources of NCGs within the steam chamber. One source is the evolution of solution gas dissolved in the bitumen. As the bitumen is heated the solubility of the gas decreases as it becomes energized, resulting in its evolution from the bitumen into the steam chamber. A second major source involves the production of NCGs from reactions taking place between water and organic compounds at elevated temperatures and pressures. This process can for example include bitumen thermal cracking at elevated temperatures or low temperature oxidation. Other minor sources of NCGs may include the co-injection of gases with steam, for example as may be undertaken in order to prevent steam hammer or for the purpose of using the NCG to facilitate measurements of the steam chamber pressure.

[0008] NCGs in the steam chamber can offer both benefits and challenges to the optimal performance of a SAGD system. For example, US Patent No. 8,596,357 describes methods for adding a buoyancy-modifying agent to injected steam, such as an additional NCG, to help cause NCGs to accumulate at the top of the steam chamber. This approach reflects the fact that NCGs tend to be light and therefore buoyant, so that any NCG that is liberated or generated lower in the steam chamber will tend to rise to a higher part of the steam chamber, and any NCG produced or released higher in the

steam chamber will tend to remain in the upper elevations of the steam chamber. Other aspects of fluid dynamics in the SAGD process influence this vertical NCG flow. For example, as injected steam migrates from the injection well to the steam chamber walls, the steam in effect drags NCGs with it, and as it condenses and transfers heat to the bitumen, the volume formerly occupied by steam is significantly reduced. This, in combination with various factors, including the fact that NGCs generally have much greater vapour pressures compared to steam at lower temperatures, creates a region that can draw NCGs to the margins of the steam chamber.

[0009] Accordingly, a combination of their non-condensable nature, buoyancy, source and the lower relative pressures at the steam bitumen interface, generally leads to NCG accumulation high in the steam chamber near the walls. This poses challenges, in the sense that the NCGs may act as an insulator, lowering the partial pressure of the steam and therefore the saturation temperature, thus inhibiting lateral growth of the steam chamber. In addition, it may make it difficult to remove the NCGs in a conventional SAGD operation, where the single source of production is a well located at the bottom of the steam chamber.

[0010] There are a number of potential problems associated with attempting to remove NCGs from the reservoir by producing them at a SAGD producer well. The NCGs are relatively mobile and, although buoyant, might be pulled down into the producing well by the application of sufficient fluid drawdown. However, accompanying the NCG phase is a steam phase, or a hot water phase which is capable of flashing to steam as it approaches the low pressures present in the vicinity of the producer. As a consequence, attempts to produce the NCGs can result in an undesirable condition whereby excessive quantities of steam are also produced.

[0011] The management of NCGs is further complicated by the fact that gravity-dominated in situ recovery processes, such as SAGD, rely on vertical flow and displacement. However, given the long horizontal wells that are normally associated with this type of process, and the (axial) flows along the length of the wells, the resulting

(radial or transverse) flows from reservoir to well, and vice versa, will tend to be non-uniform, even in a homogeneous reservoir.

[0012] In the context of the present application, various terms are used in accordance with what is understood to be the ordinary meaning of those terms. For example, “petroleum” is a naturally occurring mixture consisting predominantly of hydrocarbons in the gaseous, liquid or solid phase. In the context of the present application, the words “petroleum” and “hydrocarbon” are used to refer to mixtures of widely varying composition. The production of petroleum from a reservoir necessarily involves the production of hydrocarbons, but is not limited to hydrocarbon production. Similarly, processes that produce hydrocarbons from a well will generally also produce petroleum fluids that are not hydrocarbons. In accordance with this usage, a process for producing petroleum or hydrocarbons is not necessarily a process that produces exclusively petroleum or hydrocarbons, respectively. “Fluids”, such as petroleum fluids, include both liquids and gases. Natural gas is the portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in natural underground reservoirs, and which is gaseous at atmospheric conditions of pressure and temperature. Natural Gas may include amounts of non-hydrocarbons. The abbreviation POIP stands for “producible oil in place” and in the context of the methods disclosed herein is generally defined as the exploitable or producible oil structurally located above the production well elevation.

[0013] It is common practice to segregate petroleum substances of high viscosity and density into two categories, “heavy oil” and “bitumen”. For example, some sources define “heavy oil” as a petroleum that has a mass density of greater than about 900 kg/m3. Bitumen is sometimes described as that portion of petroleum that exists in the semi-solid or solid phase in natural deposits, with a mass density greater than about 1000 kg/m3 and a viscosity greater than 10,000 centipoise (cP; or 10 Pa.s) measured at original temperature in the deposit and atmospheric pressure, on a gas-free basis. Although these terms are in common use, references to heavy oil and bitumen represent categories of convenience, and there is a continuum of properties between heavy oil and bitumen. Accordingly, references to heavy oil and/or bitumen herein

include the continuum of such substances, and do not imply the existence of some fixed and universally recognized boundary between the two substances. In particular, the term “heavy oil” includes within its scope all “bitumen” including hydrocarbons that are present in semi-solid or solid form.

[0014] A reservoir is a subsurface formation containing one or more natural accumulations of moveable petroleum, which are generally confined by relatively impermeable rock. An “oil sand” or “tar sand” reservoir is generally comprised of strata of sand or sandstone containing petroleum. A “zone” in a reservoir is merely an arbitrarily defined volume of the reservoir, typically characterised by some distinctive property. Zones may exist in a reservoir within or across strata, and may extend into adjoining strata. In some cases, reservoirs containing zones having a preponderance of heavy oil are associated with zones containing a preponderance of natural gas. This “associated gas” is gas that is in pressure communication with the heavy oil within the reservoir, either directly or indirectly, for example through a connecting water zone.

[0015] A “chamber” within a reservoir or formation is a region that is in fluid communication with a particular well or wells, such as an injection or production well. For example, in a SAGD process, a steam chamber is the region of the reservoir in fluid communication with a steam injection well, which is also the region that is subject to depletion, primarily by gravity drainage, into a production well.

SUMMARY OF THE INVENTION

[0016] The present invention addresses the challenge of beneficially removing from the reservoir significant quantities of NCG while governing the production of steam. The principle employed in this invention involves the creation of a convective component of NCG flow so as to utilize certain characteristics of NCGs, and thereby develop a favourable NCG flow path. Development of this favourable flow path can involve improved NCG effective permeability, buoyancy, drag, or combinations thereof, all within the overall gravity-dominated oil recovery processes which functions to separate to some degree the NCG phase from the steam phase so that a greater quantity of the

former can be removed from the reservoir while avoiding excessive production of the latter.

[0017] In various aspects, the invention provides processes for removing hydrocarbons and non-condensing gases from an expanding steam chamber during and following the ramp-up phase of a thermal recovery process, such as a SAGD process, for example from a vertically expanding steam chamber during ramp-up and a radially expanding steam chamber following ramp-up. In selected embodiments, the arrangement of wells within a formation will accordingly follow the pattern of typical SAGD process. Althernative arrangements of wells include multilateral wells, and single well implementations of thermal recovery processes. As such, the reservoir will have within it a steam chamber with a peripheral zone of mobile hydrocarbons. In select embodiments, a generally horizontal segment of a production well will be in fluid communication with the zone of mobile hydrocarbons, and a generally horizontal segment of an injection well will be in fluid communication with the steam chamber. The horizontal segment of the injection well will generally be parallel to and vertically spaced apart above the horizontal segment of the production well. Mobilized hydrocarbons are collected from the reservoir through the production well and NCG is recovered through the production well and/or a vent well. In some embodiments, the production and/or vent wells may be throttled to adjust production conditions, for example in the production well by maintaining the temperature of the produced bitumen stream just below saturated steam conditions, to limit production of steam.

[0018] Processes of the invention may take place in the context of a reservoir having a steam chamber with a peripheral zone comprising condensing steam, non-condensing gas and mobile hydrocarbons. The steam chamber may have a longitudinal axial dimension formed by a SAGD wellpair. A generally horizontal segment of a production well will be in fluid communication with the zone of mobile hydrocarbons. A generally horizontal segment of an injection well will be in fluid communication with the steam chamber, generally parallel to and vertically spaced apart above the horizontal segment of the production well. An injection fluid that generally includes steam may be injected through the horizontal segment of the injection well at a range of selected bottom hole

injection pressures that vary between steam injection points that are spaced apart along the length of the horizontal segment of the injection well, so as to form an axial pressure gradient within the steam chamber from a high pressure region to a low pressure region. The injection of fluid may be carried out so as to concurrently:

i) mobilize the heavy oil in the peripheral zone to form the mobile hydrocarbons, so that the mobile hydrocarbons flow downwardly and towards the production well in a gravity dominated process;

ii) mobilize the non-condensing gas in the peripheral zone, so that the non-condensing gas flows in the axial dimension of the steam chamber in a convective flow motivated by the axial pressure gradient, moving from the high pressure region to the low pressure region; and,

iii) radially expand the steam chamber.

[0019] In some embodiments, steam injection points and one or more gas production points may be arranged so that the non-condensing gas is preferentially delivered to a non-condensing gas production region of the formation, which may for example coincide with a segment of the production well, or a vent well, that resides in the low pressure region of the axial pressure gradient. Mobilized hydrocarbons and non-condensing gas may for example be produced through the production well, thereby removing heavy oil and non-condensing gases from the reservoir. The steam injection points may for example be arranged by adjusting the relative vertical position of steam injection points along the injection well, or by adjusting the relative horizontal position of steam injection points along the injection well. In some embodiments, the adjustment in the relative position of steam injection points may for example be accomplished changing the physical position of such points in well completions, alternatively optional points of steam injection may be provided in a well completion, and these optional points may be opened or closed to adjust the effective positions of steam injection.

[0020] The principal non-condensing gas production region may for example be a portion of the production well may for example be proximal to the heel segment of the production well, proximal to the toe segment of the production well, or intermediately spaced apart from the heel segment of the production well and the toe segment of the

production well. In a SAGD field comprising a plurality of well pairs, further alternatives are available for arranging an axial pressure gradient so as to position the principal non-condensing gas production regions. For example, if two neighboring SAGD well pairs are in communication through a conjoined steam chamber, injection may be terminated in one well pair, or steam injection points may be closed along most or all of the longitudinal extent of a well pair, for example so that only a relatively small amount of steam is injected at the toe of a well pair. In these configurations, NCG may for example be produced through the casing of one or more wells. Alternatively, injection of steam may be continued or increased in a neighboring well pair so as to create an axial pressure gradient along one well pair which is communicated through the conjoined steam chamber to an adjoining well pair.

[0021] In selected embodiments, a vent well may be provided in the reservoir in fluid communication with the steam chamber, so that non-condensing gases may be produced from the vent well so as to amplify the axial pressure gradient within the steam chamber.

BRIEF DESCRIPTION OF THE DRAWINGS

[0022] **Figure 1** is schematic illustration of a typical SAGD well pattern, showing paired injector and producer well pairs, each have a heel and a toe within the hydrocarbon rich pay zone of the formation.

[0023] **Figure 2** is a cross sectional view of an exemplary completion for an injector well, referring to the use of slotted liners, as for example disclosed in Canadian Patent Application 2,616,483 of Cenovus Energy Inc. published 29 June 2008.

[0024] **Figure 3** is a cross sectional view of an exemplary completion for a production well, in a start up configuration for circulation, illustrating an embodiment employing gas lift.

[0025] **Figure 4a** is a cross sectional view of an exemplary completion for a production well, illustrating an embodiment employing an electronic submersible pump

(ESP) for production operations following start up. Typically, after circulation start-up, the 2" coiled tubing string will be removed and the well equipped with a high temperature ESP capable of pumping fluid from the well into production gathering facilities.

[0026] **Figure 4b** is a cross sectional view of an exemplary completion for a production well, illustrating an embodiment that represents a completion of the type used in simulations modeling alternative embodiments.

[0027] **Figure 5** is a graph illustrating oil viscosity as a function of temperature in a computational model of alternative embodiments of the invention.

[0028] **Figure 6** is a graph illustrating the solution gas ratio as function of pressure at a reference temperature of 12°C in a computational model of alternative embodiments of the invention.

[0029] **Figure 7** is a graph illustrating the oil-water relative permeability curves in a computational model of alternative embodiments of the invention.

[0030] **Figure 8** is a graph illustrating the Oil-Gas relative permeability curves in a computational model of alternative embodiments of the invention.

[0031] **Figure 9** is a ternary cross section through the steam chamber one year into SAGD operation, where the lightest grey represents oil, intermediate shades of grey represent mobilized fluids and the darkest grey is gas. From left to right, the panels illustrate: first, **Figure 9a,** a plane where both the producer and injector are slotted; second, **Figure 9b,** a plane where the injector is blanked; and third, **Figure 9c,** a plane where the producer is blanked. The small black arrows represent the direction of gas flux.

[0032] **Figure 10** is a ternary cross section in the IK plane, slicing through the steam chamber approximately 5 years into the SAGD process, where the lightest grey

represents oil, intermediate shades of grey represent mobilized fluids and the darkest grey is gas. From left to right, the panels illustrate: first, **Figure 10a,** a plane where both the producer and injector are slotted; second, **Figure 10b,** a plane where the injector is blanked; and third, **Figure 10c,** a plane where the producer is blanked. The small black arrows represent the direction of gas flux in that plane. Note the clockwise circulation of NCG near the chamber edge, with little to no flow down to the producer.

[0033] **Figure 11** is ternary cross section in the IK plane, slicing through the steam chamber near the heel of the well approximately 5 years into the SAGD process, where the lightest grey represents oil, intermediate shades of grey represent mobilized fluids and the darkest grey is gas. From left to right, the panels illustrate: first, **Figure 11a,** a plane where both the producer and injector are slotted; and second, **Figure 11b,** a plane where the injector is blanked. The small black arrows represent the direction of gas flux in the plane. Note the same clockwise circulation of NCG near the chamber edge, but with flow to the production well.

[0034] **Figure 12** is a JK cross section through the Base Case (top) and High Injector Landing (bottom) embodiments, illustrating the difference in the trajectory of the injection well at the heel (to the left). The difference in vertical and horizontal scales cause the landing to appear steeper than it actually is.

[0035] **Figure 13** is a JK cross section through the Base Case (top) and Sinusoidal (bottom) embodiments, illustrating the difference in the trajectory of the injection well along the entire well length, with the heel on the left.

[0036] **Figure 14** is a graph illustrating daily and cumulative oil production for alternative embodiments having injector completion design change cases.

[0037] **Figure 15** is a graph illustrating the cumulative steam oil ration (CSOR) and oil recovery factor for the alternative embodiments having injector completion design changes.

[0038] **Figure 16** is a graph illustrating the producing gas/oil ration (GOR) and cumulative gas production for the alternative embodiments having various injector completion design changes.

[0039] **Figure 17** is a bar chart showing the number of days to reach 60% POIP recovery factor for alternative embodiments having injector completion design changes, including incremental values relative to the Base Case.

[0040] **Figure 18** is a bar chart showing CSOR at 60% POIP recovery factor for alternative embodiments having injector completion design changes, including incremental values relative to the Base Case.

[0041] **Figure 19** is a bar chart showing cumulative gas production at 60% POIP recovery factor for alternative embodiments having injector completion design changes, including incremental values relative to the Base Case.

[0042] **Figure 20** is a bar chart showing average oil production rate for alternative embodiments having injector completion design changes. Average oil production rate is defined as the cumulative production at 60% POIP recovery factor, divided by the number of days to reach 60% POIP recovery factor . Incremental values are relative to the Base Case.

[0043] **Figure 21** is a graph illustrating cumulative NCG production at the point of 60% POIP recovery factor for the Base Case and the embodiment having the best combination of blanked injector casing joints.

[0044] **Figure 22** is a JK cross section through the Base Case (top) and the embodiment having the best combination of blanked injector casing joints (bottom). The image shows a reservoir pressure profile several years into the SAGD process.

[0045] **Figure 23** is a graph illustrating injector tubing string pressure (kPaa) 3 years into SAGD operations for the Base Case and the embodiment having the best combination of blanked injector casing joints.

[0046] **Figure 24** is a JK cross section through the Base Case (top) and the embodiment having the best combination of blanked injector casing joints (bottom, showing a ternary view three years into the SAGD process.

[0047] **Figure 25** is JK cross section through the Base Case (top) and the High Injector Landing case (bottom). The image shows a reservoir pressure view four years into the SAGD process.

[0048] **Figure 26** is a JK cross section through the Base Case (top) and the Sinusoidal Injector embodiment (bottom). The image shows a reservoir pressure view 7 years into the SAGD process.

[0049] **Figure 27** is a graph illustrating Cumulative NCG production at the point of 60% POIP recovery factor for the Base Case and the Sinusoidal Injector case.

[0050] **Figure 28** is a graph illustrating daily and cumulative oil production for various parallel vent well embodiments.

[0051] **Figure 29** is a graph illustrating CSOR and oil recovery factor for various parallel gas vent well embodiments.

[0052] **Figure 30** is a graph illustrating SAGD production well GOR and total cumulative gas production for various parallel vent well embodiments.

[0053] **Figure 31** is a bar chart illustrating the number of days to reach 60% POIP recovery factor for the various parallel gas vent well embodiments. The incremental values are relative to the Base Case.

[0054] **Figure 32** is a bar chart illustrating CSOR at 60% POIP recovery factor for the various parallel gas vent well embodiments. The incremental values are relative to the Base Case.

[0055] **Figure 33** is a bar chart illustrating cumulative gas production at 60% POIP recovery factor for the various parallel gas vent well embodiments. The incremental values are relative to the Base Case.

[0056] **Figure 34** is a bar chart illustrating average oil production rates for the various parallel gas vent well embodiments. Average oil production rate is defined as the cumulative production at 60% POIP recovery factor, divided by the number of day to reach 60% POIP recovery factor . The incremental values are relative to the Base Case.

[0057] **Figure 35** is a graph illustrating vent well cumulative and daily gas production rate over time, showing the inverse relationship between gas production and vent well length, which coincides with the poor performance of longer wells in the longer term.

[0058] **Figure 36** is a JK cross section through the Base Case (top), 225 m Vent Well case (middle) and the 800 m Vent Well case (bottom). The image shows reservoir pressure 2.5 years into the SAGD process.

[0059] **Figure 37** is a JK cross section through the 225 m Vent Well case (top) and the Selectively Slotted 225 m Vent Well case (bottom). The image shows reservoir pressure 2.5 years into the SAGD process.

[0060] **Figure 38** is a graph illustrating vent well daily gas production rate and cumulative gas production for the embodiments using various maximum steam production operating constraints in a 225 m Vent Well.

[0061] **Figure 39** is a graph illustrating daily oil rate and cumulative oil production for the embodiments using various maximum steam production operating constraints in a 225 m Vent Well.

[0062] **Figure 40** is graph illustrating CSOR and recovery factor for embodiments using various maximum steam production operating constraints in a 225 m Vent Well.

[0063] **Figure 41** is a JK cross section for the 1 T/d (top), 10 T/d (middle) and 25 T/d (bottom) steam production operating constraint embodiments. The image shows reservoir pressure 3.5 years into the SAGD process.

[0064] **Figure 42** is a graph illustrating daily and cumulative oil production for an embodiment having four simultaneous perpendicular gas vent wells (GV 1-4), and the four alternative single perpendicular vent well embodiments (GV-1, GV-2, GV-3, and GV-4), compared to the Base Case.

[0065] **Figure 43** is a graph illustrating cSOR and oil recovery factor for an embodiment having four simultaneous perpendicular gas vent wells (GV 1-4), and the four alternative single perpendicular vent well embodiments (GV-1, GV-2, GV-3, and GV-4), compared to the Base Case.

[0066] **Figure 44** is a graph illustrating SAGD production well GOR and total cumulative gas production for an embodiment having four simultaneous perpendicular gas vent wells (GV 1-4), and the four alternative single perpendicular vent well embodiments (GV-1, GV-2, GV-3, and GV-4), compared to the Base Case.

[0067] **Figure 45** is a bar graph illustrating the number of days to reach 60% POIP recovery factor for an embodiment having four simultaneous perpendicular gas vent wells (GV 1-4), and the four alternative single perpendicular vent well embodiments (GV-1, GV-2, GV-3, and GV-4), compared to the Base Case.

[0068] **Figure 46** is a bar graph illustrating cSOR at 60% POIP recovery factor for an embodiment having four simultaneous perpendicular gas vent wells (GV 1-4), and the four alternative single perpendicular vent well embodiments (GV-1, GV-2, GV-3, and GV-4), with incremental values relative to the Base Case.

[0069] **Figure 47** is a bar graph cumulative gas production at 60% POIP recovery factor for an embodiment having four simultaneous perpendicular gas vent wells (GV 1-4), and the four alternative single perpendicular vent well embodiments (GV-1, GV-2, GV-3, and GV-4), with incremental values relative to the Base Case.

[0070] **Figure 48** is a bar graph average oil production rate for an embodiment having four simultaneous perpendicular gas vent wells (GV 1-4), and the four alternative single perpendicular vent well embodiments (GV-1, GV-2, GV-3, and GV-4. Average oil production rate is defined as the cumulative production at 60% POIP recovery factor, divided by the number of day to reach 60% POIP recovery factor . Note that the incremental values are relative to the Base Case.

[0071] **Figure 49** is a JK cross section through the Base Case (top), GV-1 (middle) and GV-4 (bottom) single perpendicular vent well embodiments. The image shows reservoir pressure various at points in the SAGD process, illustrating the difference in magnitude and orientation of the steam chamber pressure gradients.

[0072] **Figure 50** is JK cross section through the GV-1 (top) and GV-2 (bottom) single perpendicular vent well embodiments. The image shows reservoir pressure at various points in the SAGD process, illustrating the difference in magnitude and orientation of the steam chamber pressure gradients.

[0073] **Figure 51** is a graph illustrating daily and cumulative oil production for an embodiment having a truncated, elevated vent well 75 m in length ("Elevated – 75 m"), and an alternative embodiment having a deviated vent well in which the longitudinal segment of the vent well deviates from the vertical plane of the SAGD well pair at the 75 m point, and extends on a lateral strike for 800 m ("Deviated – 800 m). For comparison, data is also provided for the 225 m Vent Well embodiment and the Base Case.

[0074] **Figure 52** s a graph illustrating cSOR and oil recovery factor for an embodiment having a truncated, elevated vent well 75 m in length ("Elevated – 75 m"),

and an alternative embodiment having a deviated vent well in which the longitudinal segment of the vent well deviates from the vertical plane of the SAGD well pair at the 75 m point, and extends on a lateral strike for 800 m ("Deviated – 800 m). For comparison, data is also provided for the 225 m Vent Well embodiment and the Base Case.

[0075] **Figure 53** is a graph illustrating daily (solid lines) and cumulative (dashed lines) oil production for an embodiment having a shared deviated vent well, in which the deviated lateral strike of a vent well extends laterally across two well pairs, in effect providing a shared vent well that services two adjoining steam chambers. Data are provided from the two SAGD well pairs, identified in the graph as "Deviated #1" and "Deviated #2." The vent well in this embodiment originates above the heel of the Deviated #1 SAGD well pair, and traverses towards the tow of the Deviated #2 SAGD well pair.

[0076] **Figure 54** is a graph illustrating cSOR (solid lines) and oil recovery factor (dashed lines) for an embodiment having a shared deviated vent well, in which the deviated lateral strike of a vent well extends laterally across two well pairs, in effect providing a shared vent well that services two adjoining steam chambers. Data are provided from the two SAGD well pairs, identified in the graph as "Deviated #1" and "Deviated #2." The vent well in this embodiment originates above the heel of the Deviated #1 SAGD well pair, and traverses towards the tow of the Deviated #2 SAGD well pair.

DETAILED DESCRIPTION OF THE INVENTION

[0077] Various aspects of the invention involve the drilling of one or more wells that are situated and operated so as to form a hydrocarbon extraction chamber within a reservoir. This may for example include SAGD well pairs within a reservoir 11, as illustrated in Figure 1, with each injector well 13, 19, 23, paired with a corresponding producer well 15, 17 and 21. Each well has a completion 14, 12, 16, 18, 20 and 22 on surface 10, with a generally vertical segment leading to the heel of the well, which then extends along a generally horizontal segment to the toe of the well. In very general

terms, to provide a general illustration of scale in selected embodiments, these well pairs may for example be drilled in keeping with the following parameters. There may be approximately 5 m depth separation between the injection well and production well. The SAGD well pair may for example average approximately 800 m in length. The lower production well profile may generally be targeted so that it is approximately 1 to 2 m above the SAGD base. As discussed in more detail below, the development of steam chambers around each well pair may be illustrated in cross sectional views along axis 24, which is perpendicular to the longitudinal axial dimension of the horizontal segments of the well pairs. Alternative arrangements of wells are also available, for example SAGD well pairs may be used with wedge or infill wells, and the injector and/or producer wells may be branches of a multilateral well, for example cooperative multilateral wells (SAGD-EL) or "fishbone" multilateral wells.

[0078] In alternative embodiments, rather than using a well pair, one or more single horizontal or vertical wells may be used for injection and production in *in-situ* hydrocarbon recovery processes such as, but not limited to, steam-assisted gravity drainage (SAGD), a solvent aided process (SAP) or "huff and puff" processes. For example, CA 2,844,345 to Gittins, discloses a thermal/solvent oil recovery process for producing hydrocarbons using a single vertical or inclined well. The process may be preceded by start-up acceleration techniques to establish communication in the formation between an injection means and a production means within the single well.

[0079] In the case of single well embodiment, fluid communication refers to fluid flow in the formation between the injection means (or an injection component) and the production means (or a production component) in the single well. For example, the injection and production components may be conduits, optionally tubing, and may be isolated from one another by way of a packer, by positioning the injection and production means a suitable distance apart, by positioning the injection means in the wellbore closer to the surface than the production means in the case of a vertical well, or by way of openings or perforations in the tubing or well casing over selected wellbore interval(s) to permit both outlet of injected fluids and inlet of production fluids. The positioning of the injection and production means may be adapted depending on the

particular well and formation. For example, processes may make use of an injection tubing string which has openings only at or towards one end of the horizontal well, for example at the toe end, to permit egress of injected fluids, and openings or perforations along the liner or outer casing of the wellbore to permit injection into the reservoir of mobilizing fluids over a selected interval of the wellbore. Positioned downstream therefrom along the casing or liner of that same wellbore, openings may be provided to permit production from the reservoir of mobile and mobilized fluids. In addition, one or more surfactants can be used to facilitate or accelerate a single well start-up process, or to improve fluid communication.

[0080] Alternative aspects of the invention involve completing wells in various configurations. Exemplary completions for injector, producer on gas lift, producer on electronic submersible pump (ESP) and simulated producer are shown in Figures 2, 3, 4a and 4b respectively.

[0081] In accordance with various aspects of the invention, detailed computational simulations of reservoir behaviour have been carried out. For purposes of illustrating the invention, a 'base case' model was constructed. For purposes of illustrating alternative embodiments, slight modifications to the base case may be made when constructing the other models. Typically such adjustments are restricted to completion design or operating constraints of the well pair. In other models, additional wells were added, but there was no change to the grid, reservoir property population, PVT or relative perm data.

Simulation Grid

[0082] A half element of symmetry was employed to ensure faster run times. The model had 30 m pay, 3 m bypassed pay and an 800 m long well. There was 31 m of overburden and 31 m underburden. Grid dimensions were 26 x 64 x 43, for a total of 71,552 blocks. Block dimensions were as follows:

I – direction: 1m 24*2m 1m (26 blocks, total length of 50 m)

J – direction: 64*12.5m (64 blocks, total length of 800 m)

K – direction: 16 m 8 m 4 m 2 m 35*1 m 2 m 4 m 8 m 16 m (43 blocks, total length of 95 m)

[0083] The high level of discretization in the J direction was done to model the blanking and slotting of casing joins. A typical casing joint is approximately 12-13 m in length.

Reservoir Properties

[0084] The grid was populated using the following reservoir variables:

Temperature = 12 ˚C

Φ = 0.33

Kh = 7.0 D

Kv = 4.2 D

Reference pressure of 2,400 kPa at the top of the SAGD pay

Sw = 0.215

So = 0.785

Mass Fraction Oil of Dead Oil = 0.85

Mass Fraction Oil of CH4 = 0.15

[0085] The thermal properties of the reservoir were characterized using two rock types. Rock type one represented clean sand and was used to populate a selected pay, representing the McMurray formation in Alberta, Canada. A second rock type representing shale was used to populate the over and underburden grid. The properties of the two rock types were defined with the following properties:

Rocktype 1 (Sand)

Porosity Reference Pressure = 100 kPa

Compressibility = 1e-6 1/kPa

Volumetric Heat Capacity 2.39e6 J/(m^3*C)

Rock Thermal Conductivity = 196,820 J/(m*day*C)

Water Thermal Conductivity = 552,960 J/(m*day*C)

Oil Thermal Conductivity = 0

Gas Thermal Conductivity = 0

Rocktype 2 (Shale Overburden & Underburden)

Porosity Reference Pressure = 100 kPa

Compressibility = 1e6 1/kPa

Volumetric Heat Capacity 2.39e6 J/(m^3*C)

Rock Thermal Conductivity = 146,880 J/(m*day*C)

Water Thermal Conductivity = 0

Oil Thermal Conductivity = 0

Gas Thermal Conductivity = 0

PVT Data

[0086] The PVT model consisted of three components; water, dead oil and methane, with characteristics as illustrated in Figures 5 and 6.

Relative Permeability

[0087] The oil-water relative permeability curves have the following properties:

Connate Water Saturation = 0.2

Critical Water Saturation = 0.2

Residual Oil Saturation = 0.15

Irreducible Oil Saturation = 0.15

Max relative water permeability = 0.559

Max relative oil-water permeability = 0.95

[0088] The oil-gas relative permeability curves have the following properties:

Critical Gas Saturation = 0.05

Residual Liquid Saturation = 0.3

Max relative gas permeability = 0.72

Max relative oil-gas permeability = 0.95

[0089] Relative permeability properties are illustrated in Figures 7 and 8.

Operating Constraints

[0090] The simulation was initiated with a circulation phase in order to establish inter wellpair communication. Four numerical wellbore models (Flexwells™) were used to

mimic the operation of the SAGD well pairs during this phase. Circulation lasted for 2 months and used the following parameters and constraints for well definition and operation:

Producer Annulus (Producer Well)

Min Bottom Hole Pressure = 5,100 kPa

ID = 0.159m

OD = 0.178m

Producer Circulation Tubing String (Injector Well)

Max Water Rate = 150 m^3/d

Max Bottom Hole Pressure = 8,600 kPa

ID = 0.078

OD = 0.089

Injector Annulus (Producer Well)

Min Bottom Hole Pressure = 4,900 kPa

ID = 0.159

OD = 0.178

Injector Coil Tubing (Injector Well)

Max Water Rate = 150 m^3/d

Max Bottom Hole Pressure = 8,600 kPa

ID = 0.04

OD = 0.045

[0091] As exemplified, the SAGD operational phase begins after circulation, takes place at low pressure and lasts until the start of blow down. During this period, three numerical wellbore models were defined, with completions analogous to that shown in Figure 4b, with the following parameters and constraints in order to mimic SAGD well pair operation:

Injector Annulus (Shutin)

ID = 0.159

OD = 0.178

Injector Tubing String (Oprn)

ID = 0.104

OD = 0.134

Injector liner block 1, 1, 14 kept at 2,600 kPa via trigger

Injector Tubing String (Injector Well)

Max Bottom Hole Pressure initiated at 2,900 kPa, but later defined via trigger

Max Water Rate = 1,200 m^3/d

Tubing has 3 steam splitters at 131 m, 331 m and 581 m

1st Sub: 1 cm diameter holes, 0.8 discharge coefficient, 6 holes

2nd Sub: 1 cm diameter holes, 0.8 discharge coefficient, 12 holes

3rd Sub: 1 cm diameter holes, 0.95 discharge coefficient, 32 holes

Producer Annulus (Producer Well)

Max Liquid Rate = 200 m^3/d

Min Bottom Hole Pressure = 1,900 kPa

Max Steam Production = 10 m^3/d CWE

[0092] For the first year and half of the SAGD operational period, gas flow follows a relatively consistent pattern as illustrated in **Figure 9**. Liberated NCG migrates from its place of origin to the top and edges of the steam chamber, where it accumulates and is eventually drawn down along the chamber wall to the production well. However, it appears that blanking or slotting the production and injection liner joints can significantly alter gas flow. When both joints are slotted the gas behaves as previously described, flowing down the chamber wall to the production well. Blanking an injection joint will alter the flow of gas so that it flows down towards the producer along the chamber wall and through the center of the chamber. The lack of injection prevents steam from displacing the NCG and carrying it towards the chamber boundaries, simultaneously creating a plane of lower pressure relative to the surrounding regions. This promotes the backflow of gas into the chamber and down to the producer. When a joint in the production well is blanked, no production occurs at this location. NCG and any other fluids are forced to move parallel to the SAGD well pair in order to locate a slotted joint for production.

[0093] These flow regimes establish a means of gas production during the early life of a well pair. Regions where both the injector and producer are slotted act as the main method of removing NCG. Computational modeling characterizes an isosurface which represents the position within the reservoir where the volumetric flow rate of NCG is equal to 1 m^3/d. Outside of this surface the rate is less than 1 m^3/d, but greater than 1 m^3/d within the surface. The characteristics of this surface indicate that there is little to no NCG flow where the producer has been blanked, gas travels down the chamber wall for production where the producer is slotted and down both the chamber wall and through the chamber where the injector is blanked.

[0094] It has been discovered that the non-condensing gas flow regime begins to alter in the SAGD process as the steam chamber expands, for example at approximately 2 years into the process as simulated, reflecting changes that may occur on alternative time lines in practice. Up to this point, NCGs are generally produced along the entire length of the production well. Now NCG productivity of any slotted producer joints not near the heel begins to diminish. However, the opposite is true of any producer slotted joints near the heel. This is evident from the fact that, at this point in the model, the 1 m^3/d isosurface connecting slotted producer joints not near the heel with the steam chamber wall has dispersed everywhere except at the heel.

[0095] An aspect of the invention is the recognition of this evolving behavior of NCGs. As the near wellbore steam chamber is depleted of oil, this limits the amount of gas being evolved near the production well, and therefore restricts the well's ability to attract nearby gas. Simultaneously, the major point of NCG accumulation and generation (the chamber wall), has moved further from the production well. This increased distance makes it difficult for the production well to pull NCGs away from the steam chamber wall; which is further exaggerated towards the toe of the well pair, due to the ever decreasing drawdown flows. The 1 m^3/d isosurface shows that this trend continues with time, so that the main mechanism for gas production in the operational phase of SAGD is through the slotted joints at the heel.

[0096] In a mature SAGD system, it has been discovered that NCG continues to accumulate at the chamber wall along the entire length of the well. However, cross sections perpendicular to the well pair show that the majority of NCG is in a holding pattern at the wall of the chamber. NCG is liberated or generated at the bitumen steam interface, drawn down to the bottom of the chamber wall, where it reverses directions and rises back to the top of the chamber. **Figure 10** demonstrates that this cycle is repeated regardless of whether or not the injector or producer is slotted or blanked.

[0097] In one aspect, the present invention involves the recognition that, in order to be produced in the operational phase of SAGD, NCGs must migrate laterally along the chamber wall, in a direction parallel to the wellpair. Once NCG reaches the heel, the inventors have recognized that it will be drawn down into the production well. Further, the efficiency of gas production at the heel is impacted by the completion design of the injection well. Regions where the production well is slotted, but the injector is blanked, produce significantly more gas than those where both wells are slotted, as illustrated in **Figure 11**.

[0098] In view of the foregoing, the present invention provides a number of modifications that can be made to SAGD systems in order to improve operational NCG production. In selected embodiments, the invention involves arranging the locations of steam injection to improve in situ NCG mobilization and/or NCG production, for example by elevating portions of the injector well or by altering the longitudinal spacing of points of steam injection along the injector well.

Examples

[0099] A number of alternative aspects of the invention are exemplified herein, with discrete examples illustrating the effects of each embodiment. These approaches are not mutually exclusive, and any combination of these approaches may be combined in alternative embodiments of the invention.

Adjusting the Number of Blank Joints at the Injector's Heel

[00100] Both increasing the number of blanked injector joints and slotted production joints near the heel of a wellpair improves NCG production from a mature SAGD operation. In exemplary embodiments, joints at the injector's heel, which were slotted in the base case, were blanked in various combinations: a random variation of blanking/slotting joints at the heel of the injector well; or, blanking all of the casing joints at the heel of the injector well.

High Injector Landing or Low Producer Landing

[00101] In this embodiment, the injector's intermediate casing point (ICP) is landed at a shallower angle higher in the reservoir, so that the heel of the injector well is in effect elevated and spaced further apart vertically from the heel of the producer well (as illustrated in **Figure 12**). For example, the injector's ICP may be landed at 86 degrees and several meters above the targeted final depth of the horizontal portion of the injector well. Alternatively, the heel of the production well may be landed lower in the formation. In this embodiment, the producer's ICP is landed at a shallower angle lower in the reservoir, so that the heel of the injector well is in effect elevated and spaced further apart vertically from the heel of the injector well. In select embodiments, this may be done so as to locate the ESP outside of the productive pay, which may help to prevent steam flowing directly to the ESP and to keep the temperature around the ESP slightly cooler

Sinusoidal Injector or Producer Trajectory

[00102] In this embodiment, the injection well was drilled in a manner mimicking a sinusoidal wave. High spots in the well were located at the heel and between points of steam egress from the tubing into the annulus between the tubing and the casing, at steam splitters (as illustrated in **Figure 13**). Alternatively, the producer well may be drilled in a manner mimicking a sinusoidal wave, for example with low spots located at the heel and between points of steam egress at the injection well (at steam splitters).

[00103] To overcome start up issues with the sinussoidal injector well trajectory, the injection well was run on a stock tank water constraint defined by the injection volumes observed in the Base Case, then switched to the same BHP constraint as the Base Case 14 months into the SAGD operational phase.

Vent Wells

[00104] In these embodiments, one or more NCG vent wells may be provided within the reservoir to facilitate NCG mobilization. In alternative embodiments, vent wells may have a wide variety of locations and orientations, for example including vertical and/or horizontal segments. Horizontal segments of vent wells may for example be orientated at a strike of 0 to 90 degrees to the SAGD wellpair, i.e. parallel, perpendicular or at any intermediate angle. The trajectory of vent wells may also be varied, so that the vent wells are not limited to being flat or of one continuous elevation. In selected embodiments, as exemplified, the vent wells may have a generally horizontal trajectory parallel to the SAGD well pairs, and the vent wells are drilled from the surface. In alternative aspects of the invention, vent wells may for example be drilled as a multilateral branch from a SAGD injection well. In the exemplified embodiments, the lateral vent well was modeled with an OD of 127 mm, although in practice vent wells may be of widely varying sizes, cased in any manner to control NCG inflow, with or without tubing to control points of NCG production. In some vent well completions, inflow control devices (ICDs), or any other means to restrict or prevent gas flow in that section of the wellbore, may for example be used to control inflow. In select embodiments, as modeled, 73 mm tubing may for example be used, along with optional tubing conveyed ICDs to control inflow and produce the gas to surface. Certain aspects of vent wells were varied between modeled embodiments. These variables included well length, selectively blanking or slotting the casing joints, trajectory and operational constraints. These variables may for example be adjusted so as to orchestrate NCG mobilization in a pattern that is conducive to NCG production, including NCG production through wells other than the vent wells. In this way, vent wells may serve not only to vent NCGs, but also to maximize in situ NCG mobilization and thereby enhance overall NCG removal.

Results

[00105] **Figure 14** illustrates the impact of alternative embodiment on the daily and cumulative oil production rate compared to the Base Case: i) Blank Injector Casing Joints; ii) Injector High Landing; and, iii) Sinusoidal Injector. The alternative embodiments each improve operational SAGD performance compared to that of the Base Case. The most dramatic improvement was observed by blanking certain casing joints at the heel of the injection well, followed by the sinusoidal injector trajectory.

[00106] **Figure 15** illustrates that the improved production performance due to the design changes in the alternative exemplified embodiments has not come at the expense of Cumulative Steam-Oil Ratio or CSOR (on a cumulative basis, the relative amount of steam required to produce a unit volume of oil), illustrating the CSOR and POIP Oil Recovery Factor oil over time, compared to the Base Case, for: i) Blank Injector Casing Joints; ii) Injector High Landing; and, iii) Sinusoidal Injector.

[00107] **Figure 16** illustrates that not only do the alternative embodiments increase the cumulative NCG production from the SAGD well pair, they have dramatically improved the efficiency of NCG removal. This is demonstrated by the increase in gas oil ratio (GOR), which is plotted over time, along with cumulative gas production, compared to the Base Case, for: i) Blank Injector Casing Joints; ii) Injector High Landing; and, iii) Sinusoidal Injector embodiments.

[00108] **Figures 17** through **Figure 20** summarize the results of the alternative embodiments as incremental in comparison to the Base Case, for: i) Blank Injector Casing Joints; ii) Injector High Landing; and, iii) Sinusoidal Injector embodiments. It is evident that the alternative embodiments have improved the SAGD performance in terms of oil production and days to 60% POIP recovery factor without sacrificing efficiency, by enhancement of the well pair's ability to produce NCG.

Discussion

Adjusting the Number of Blank Joints at the Injector's Heel

[00109] The embodiment illustrated in the results section was the best of 15 different configurations of blanked/slotted injector casing joints near the heel. Every possible combination of blanking/slotting of casing joints 2-5 on the injector was attempted, with the result that all combinations of blanking/slotting of injector joints improved both oil production and GOR performance over the Base Case.

[00110] **Figure 21** shows the cumulative gas production at the time of 60% POIP recovery factor along the SAGD production well for the Base Case and the embodiment having the best combination of blanking injector casing joints, illustrating the significant increase in gas production over the Base Case at the heel.

[00111] Blanking casing joints at the heel of the injector results in an increased pressure drop from the toe to the heel of the SAGD well pair (**Figure 22**). This is evidently the result of a number of mechanistic changes within the reservoir, including the following factors disclosed by the Examples herein. One mechanism is poor pressure support at the heel of the well pair, due to the lack of steam flux into the reservoir where injector casing joints have been blanked. Another is the ability to lower bottom hole pressure in the production well further, without drawing in a significant amount of steam, due to the lack of steam injection near the heel. In the absence of the modifications disclosed in this Example, drawing down the production well to such a level would result in a significant amount of steam production that would violate the production constraint of the well, and shut in the production well. An additional mechanism is evident from the fact that the lower pressures at the heel result in higher sustained steam injection rates. The sustained higher injection rates help to increase the pressure at the end of the injector tubing string. The injector tubing string pressures plotted in **Figure 23** confirm this. These factors work together and result in elevated reservoir pressures at the toe and lower reservoir pressures at the heel.

[00112] This embodiment illustrates that creating a larger pressure gradient along the longitudinal axis of the well pair improves performance by helping to mobilize NCGs, promoting rapid migration to the heel, a natural point of production. This allows the steam chamber to grow faster, especially once the chamber has grown to the point

where NCG is generally no longer produced all along the production well, but instead must primarily migrate to the heel for production.

[00113] Surprisingly, given the number of blanked injector casing joints at the heel, and therefore the significant reduction in steam injection for that region, this embodiment illustrates sustained axial uniformity of steam chamber growth (**Figure 24**).

[00114] In alternative embodiments, aspects of the invention may involve arranging steam injection points to adjust the relative vertical and/or horizontal position of steam injection points along an injection well. For example, this may be accomplished by opening or closing steam subs situated in the injection string, using shiftable subs that can be shifted open or closed. The injection well may for example be designed so that combinations of open and closed subs may be differentially arranged over time. For example, early in the SAGD process, for example during the first two years, or for an initial period during which the SAGD well pair is capable of producing NCGs along substantially the entire length of the well pair, it may be desirable to have relatively uniform steam distribution, for example to help establish steam chamber conformance along the well pair. After this early period of steam chamber formation, as NCGs preferentially migrate to the region of the heel of the well for production, it may be beneficial to close steam subs near the heel, thus shifting steam injection towards the toe. It may also be beneficial to focus steam injection to fewer subs, for example 1/3 of the way along the well and the toe. Adjustments such as these may be carried out so as to increase the magnitude of the longitudinal pressure gradient within the steam chamber, enhancing the convective migration of NCGs to a desired point of production.

[00115] In further alternative embodiments, aspects of the invention may utilize arrangements of coil tubing, such as a coil tubing that is run concentrically or non-concentrically within the injector tubing string. Steam injection through the injector tubing string could for example be periodically stopped, while steam injection through the coil tubing is initiated. Alternatively, steam injection through the coil tubing could be periodically initiated while steam injection through the injector tubing string continues uninterrupted. In a further alternative, steam injection through the coil tubing could be

initiated at some point for an indeterminate period of time while steam injection through the injector tubing could continue or be ceased. In embodiments of this kind, delivering additional steam directly to the toe of the well may be carried out so as to provide an elevated pressure region at the toe, and thereby enhance the axial NCG pressure gradient from the toe to the heel of the well. Select embodiments may involve periodically purging the steam chamber of NCGs by cyclically injecting steam through the coil tubing. Cyclic purging could for example be combined with ESP failures. When a pump fails, the ESP could be removed, and the production well steam lifted for a period of time. The coil tubing may be used to inject steam at the toe, while the producer tubing is used to steam lift NCGs and any other available fluids to the surface. This methodology may be employed so as to create a relatively large axial pressure gradient in the steam chamber, to facilitate relatively rapid purging NCGs.

[00116] In alternative aspects of the invention, an injector well may be completed in a manner that facilitates focusing more steam injection to a specific region of the steam chamber while focusing production to a different region of the steam chamber. The injector may for example be used to create a relatively high pressure area, and the producer may be used so as to create a relatively low pressure area. In combination, this will establish an axial pressure gradient within the steam chamber, thus facilitating the convective flow of NCGs within the steam chamber. For example, with nozzle-based inflow control devices (ICDs), this may be accomplished by placing larger diameter nozzles in the region of higher and lower pressures, while placing similar sized nozzles elsewhere. In one embodiment, for example, ICDs could be arranged so that the high pressure point is located at the heel of the well and the low pressure region at the toe or vice versa.

High Injector Landing

[00117] Compared to the Base Case, in this embodiment relatively more steam is forced out of the slotted injector liner just upstream of the first steam sub in the injector tubing. In conjunction with this effect, depressed overall steam injection volumes were observed at the heel. In this embodiment, the increased distance between injector and producer at the heel was found to delay inter well communication during startup. This

retarded early chamber growth in the heel region, limiting the amount of steam injected early on in the SAGD process. Slow startup at the heel resulted in initially poor oil production relative to the Base Case. However, approximately 1.5 years into the SAGD process, the High Injector Landing embodiment begins to exhibit oil production rates that exceed those observed in the Base Case, as the result of accelerated steam chamber development at the heel. These elevated rates are a consequence of the previously depressed rates of steam chamber growth at the heel up to that point in time. Once the SAGD process has reached this point, nearly identical GORs were observed in this embodiment compared to the Base Case.

[00118] Eventually, a number of years into the SAGD project, an elevated GOR begins to be observed in the High Injector Landing embodiment. This is accompanied by improved NCG production, attended by an increased pressure difference between the toe and heel of the well pair. This axial pressure gradient helps drive NCGs to the heel for production. NCG migration is facilitated by a small increase in steam injection that is required to elevate the BHP pressure at the first injector liner joint to the target pressure, resulting in a slightly higher injector tubing string pressure. This results in a slightly higher pressure at the toe. The increased radial distance at the heel also allows for a slight drop in BHP in the production well, without pulling in extra steam. These phenomena work together, resulting in a marginal increase in the pressure differential from toe to heel (**Figure 25**), thus enhancing NCG removal and therefore improving the performance of the SAGD well pair.

Sinusoidal Injector

[00119] In this embodiment, when plotted along the length of the well, cumulative steam injection volumes exiting the liner tend to be greatest near steam splitters, at the bottom of the sinusoidal trajectory. These are the regions with the greatest pressure drops across the slotted liner, which enhances the drive of steam into the reservoir. This embodiment illustrated that this phenomenon is exaggerated by the sinusoidal injector trajectory. More steam is forced out of the liner near the steam splitters, at the base of the sinusoidal trajectory, and less steam enters the reservoir at points between the splitters, at the top of the sinusoidal trajectory. Whenever there is an increase in

wellbore elevation, it causes an increased pressure drop in the injection string, and a higher tubing head pressure is required to inject the same amount of steam. This results in elevated pressures on the tubing side at each steam splitter, which causes more outflow and higher liner side pressures, motivating the elevated cumulative steam injection volumes around the steam splitters in the Sinusoidal Injector case.

[00120] In terms of oil production, the Sinusoidal Injector initially underperforms the Base Case, but quickly surpasses it. The slow start is due to similar circumstances described in the High Injector Landing case. Increased injector-producer radial distances were present in the Sinusoidal trajectory, and these areas require a longer startup time in order to establish communication. Thus steam chamber establishment and growth is delayed in these regions. The long-term production outperformance of this embodiment is the result of increased NCG removal due to modification of the axial pressure profile of the steam chamber caused by the sinusoidal trajectory of the injector. As previously mentioned, increased pressure drops were observed in the injection tubing at points where the wellbore elevation increased. This results in lower injection tubing pressures and therefore cumulative steam injection volumes at the toe of the well when compared to the Base Case. The higher pressures at the steam subs and lower pressures at the toe cause a drastic change in the *in situ* pressure profile, illustrated in **Figure 26**.

[00121] In contrast to a typical SAGD axial steam chamber pressure gradient, highest at the toe and lowest at the heel, the Sinusoidal Injector case exhibits a profile where the steam chamber pressure is highest in the middle of the well and lowest at the toe and heel, altering the flow of NCGs in the steam chamber. In this embodiment, NCGs migrate to either the toe or the heel region for production, so that in this embodiment an NCG production zone is established at the toe in addition to one at the heel (**Figure 27**).

Vent Wells

Parallel Vent Wells

[00122] Three different gas vent well lengths were exemplified: 250 m, 450 m and 800m. The 250 and 450 m lengths were modeled such that the gas vent well would terminate between two points of injection (1st and 2nd steam subs, 2nd and 3rd steam subs). To promote NCG production, tubing conveyed inflow control devices (ICDs) were positioned at the heel of the vent well and halfway between points of steam injection (**Table 1**). A variety of alternative means may of course be used to adjust NCG production locations in a vent well.

[00123] **Table 1**- Tabulation of steam injection locations in the SAGD well pair and ICD locations in the different length parallel vent well models.

Vent Well Length (m)	Steam Injection Locations (m)				NCG Production Locations (m)			
	1	2	3	4	1	2	3	4
250	125	325	575	800	37.5	225	N/A	N/A
450	125	325	575	800	37.5	225	450	N/A
800	125	325	575	800	37.5	225	450	675

[00124] To promote NCG and limit steam production, the vent well's casing joints were blanked near areas of steam injection and left slotted between points of steam injection. This variable was tested on all three lengths of vent well with a single operating constraint, allowing for a maximum daily produced cold water equivalent (CWE) steam volume of 10 m^3.

[00125] Production from the vent well was controlled by a single operating constraint: a maximum steam production quota. The well is allowed to produce any amount or type of phase on a daily basis until a defined CWE mass of steam has been produced. All of the other sensitivities performed on the parallel vent wells were run using a daily produced CWE steam volume of 10 m^3. To exemplify how the vent well performance would be impacted by the operating constraint, max CWE steam volumes of 1, 5, 15 and 25 m^3 were tested on the 225 m selectively slotted vent well embodiment.

[00126] Vent well placement was varied in selected embodiments, with other vent well variables modeled with a parallel vent well positioned 15 m directly above the SAGD injection well. Based on the dynamics of *in situ* NCG production, there will generally be no NCG available for production at this central vent location after several years into a SAGD process. Other positional variants were accordingly modeled to exemplify the effect of the location of the gas vent well. Using the 225m selectively slotted embodiment, various other completion locations were tested, all utilizing a maximum CWE steam production volume operating constraint of $10m^3/d$. The sensitivity test involved moving the vent well vertically by ± 5m and horizontally in 4 m increments up to a maximum distance of 28 m.

[00127] **Figure 28** illustrates the impact that various lengths of parallel vent wells have on the daily and cumulative oil production rate of the SAGD well pair, evidencing the fact that introducing a vent well improves the SAGD well performance above that observed in the Base Case. For this centrally located parallel vent well, the greatest improvement was observed for the shortest vent well. Increasing well length tended to result in poorer performance.

[00128] **Figure 29** reveals that the inclusion of a vent well of any length results in an elevated CSOR relative to the Base Case, over the life of the entire example. However, the CSOR at 60% POIP recovery factor generally showed the inclusion of a gas vent well had a negligible impact.

[00129] **Figure 30** illustrates that not only have the vent wells increased the cumulative gas production dramatically over the Base Case, the vent wells have also significantly reduced the gas production load on the producer. This is demonstrated by the reduction in GOR.

[00130] **Figures 31** through **Figure 34** summarize the results of the vent well simulations, and normalize them to the Base Case. It's evident that the inclusion of a vent well improves the SAGD performance in terms of oil production, days to 60% POIP recovery factor and gas production.

[00131] In alternative embodiments, prior to the establishment of a fluid connection between a vent well and the steam chamber, the vent well may be repurposed. For example it could be used for cyclic steam stimulation to promote dilation in the upper reservoir and to accelerate connection to the steam chamber.

[00132] Upon establishing communication between the vent well and steam chamber, a dramatic improvement in oil production was observed. Peak oil rates were improved by greater than 50%; 60% POIP recovery factor timing was dramatically reduced, all with little to no impact on CSOR at 60% POIP recovery factor . This was a result of the significant increase in NCG removal by the gas vent well, which was achieved through a number of mechanisms.

[00133] During the early stages of a SAGD process, a central vent well is ideally situated to produce accumulated NCGs at the top of the steam chamber. This is evident in the exemplified embodiments by a rapid steam chamber expansion in areas in close proximity to the vent well, a phenomenon which was evident for example at a point five months after fluid connection of the vent well to the steam chamber.

[00134] Generally, the longer the vent well, the greater the peak rate of oil production. This reflects accelerated steam chamber growth along the entire length of the vent well. However, longer term performance of vent well embodiments was shown to be inversely related to vent well length, with longer vent well embodiments showing poorer performance in the long term. This is a reflection of the fact that after a certain chamber size is attained, NCGs are no longer observed to be produced along the entire SAGD well length. Also, in a mature SAGD steam chamber, NCGs are not found in the center of the steam chamber. Instead they are located near the chamber walls. As a result, in a mature steam chamber, the longer the vent well, the more it's exposed to steam. This makes it more likely for a long vent well to produce steam and exceed the CWE production constraints, forcing the shut in of the vent well. A shorter vent well, although still centrally located, has less exposure to steam during this period, and is located primarily in the vicinity of the heel, an area where the Examples herein illustrate

that NCGs accumulate. Accordingly, a shorter vent well will remain in production longer, allowing it to produce more NCGs than a longer vent well, especially in the later part of the SAGD operational phase (**Figure 35**).

[00135] **Figure 36** illustrates the fact that vent wells may be used to improve NCG production by enhancing the pressure differences in the longitudinal axial dimension of the SAGD wells, in the exemplified embodiments between the toe and heel of the wellpair. As exemplified, this helps to drive NCGs towards the heel and reduces their residence time in the steam chamber. Shorter vent wells may be used to create relatively large pressure drops, compared to longer vent wells.

[00136] In alternative embodiments, selectively slotting a vent well liner may be used as a means for controlling steam production, and thereby improving production performance. For example, the injector liner may be blanked within a selected proximity to a steam sub, with the remainder of the injection liner being slotted. The present models have revealed that selectively slotting the vent well liner in this way reduces the time to 60% POIP recovery factor, with little to no impact on the CSOR relative to non-selectively slotted vent well liners. This results in a small average oil rate increase relative to the non-selectively slotted vent well cases. In these embodiments, improved productivity is evidently not the result of blanking a high productivity steam producing zone, as evidenced by the fact that the modeled vent well toe had a greater propensity for producing steam in both models. Instead, it has been discovered that blanking a large section of the vent well effectively has two effects relevant to NCG production. One effect is to effectively reduce the length of the well, therefore limiting the exposure of the vent well to regions of the reservoir having relatively low amounts of NCGs (essentially those regions distal to the heel). The other effect is to concentrate NCG productivity along a smaller area of the well, essentially increasing and localizing the drawdown. This results in a greater pressure gradient in the chamber from toe to heel, thus driving NCGs to the heel and/or vent well for production as illustrated in **Figure 37**.

[00137] A sensitivity analysis was carried out to illustrate how variations in the maximum steam production constraint would impact the performance of the 225 m Vent

Well embodiment. It revealed that this constraint can have a relatively dramatic impact on the results and that the chosen value of 10 T/d was not necessarily the optimum. It has been discovered that increasing the magnitude of this constraint can improve both NCG removal and oil production, without impacting the CSOR at 60% POIP recovery factor, as is illustrated in **Figure 38**, **Figure 39** and **Figure 40**.

[00138] As is evident in **Figure 41**, increasing the steam production operating constraint of a vent well can improve production by allowing the vent well to stay open for a greater amount of time, while simultaneously increasing the vent well drawdown and boosting steam injection. These effects work in conjunction to increase the pressure gradient in the steam chamber, in this case from toe to heel, thus driving NCGs to the heel and/or vent well for production.

[00139] To exemplify the effects of vent well placement within the reservoir, alternative embodiments were modeled by changing the vent well location, illustrating effects on the volume of both oil and gas produced, as well as the timing of fluid production. Moving the vent well vertically had opposing effects on production depending on the direction traveled. For example moving the well down 5 m resulted in poorer performance in terms of overall oil and NCG production volumes, despite contacting the steam chamber earlier. A 5 m increase in elevation resulted in a noticeable improvement in both oil and NCG production, despite the delayed connection time with the steam chamber. Horizontal displacements in increments of 4 m were exemplified, up to a total displacement of 28 m. As the magnitude of the displacement increased, so too did the magnitude of the impact on production performance. A direct correlation was observed, with the greatest improvement in oil and gas production volumes generated by the vent well embodiment with the greatest horizontal displacement. Although moving the vent well further horizontally delayed connection with the steam chamber, it strategically placed it where NCGs accumulate in the mature steam chamber. This yielded greater NCG production volumes and better overall production performance.

[00140] In selected embodiments, for a centrally located vent well, a relatively short truncated vent well (such as 225 m or shorter) may be placed relatively high in the reservoir towards the heel region, to maximize the exposure of the vent well to NCG production zones in a mature steam chamber. The well may for example be operated with relatively liberal CWE operating constraints (being allowed to produce relatively high volumes of steam). In selected embodiments, vent wells such as this may for example be drilled as a multilateral extension from the injector well.

[00141] In alternative embodiments, vent wells of the invention may serve as a multi-purpose well (MPW) that functions differently depending on the type of application and the operational stage of the SAGD well pair/pad lifetime. For example, a vent well may be used for the purpose of steam, solvent and/or surfactant injection during operation SADG production phases. Alternatively a vent MPW may for example be used for NCG injection during ramp down or 60% POIP recovery factor stages of a SAGD project. In a further alternative, the vent MPW may be used for solvent production in the context of a solvent assisted SAGD process.

[00142] In an exemplary embodiment involving use of a vent MPW, the MPW could for example be operated in a cyclic fashion in which the well alternately produces NGC and injects steam. Alternatively, a vent MPW could similarly be utilized to inject solvent in a cyclic manner, for example to facilitate the injection of less volatile solvents that would not be fully vaporized at typical downhole operating conditions (i.e. heavier solvents that would have a greater effect on reducing oil viscosity). Similarly, a vent MPW could be utilized to inject surfactant in the top sections of the reservoir, for example using long chain, non-vaporizable surfactants. Combinations of these approaches are also contemplated.

[00143] During the final phases of a SAGD process, when NCG production is not desired, a vent MPW could for example be used for methane co-injection (with steam) during the ramp down stage and for pure methane or air injection during the 60% POIP recovery factor stage. Also in the ramp down stages of a solvent assisted SAGD process, a vent MPW may for example be used for solvent production. Also, sections of

the vent wells may be blanked over time, for example using sliding sleeves or other flow control mechanisms.

Perpendicular Vent Wells

[00144] The following example relates to two categories of perpendicular vent well. One category is exemplified by the simulations containing a single vent well. The other category is exemplified by simulations containing four perpendicular vent wells. In both categories, all simulations were based on the same model used in the Base Case, with vent well(s) having a horizontal trajectory perpendicular to the SAGD well pairs. A well with an OD of 178 mm was used to model the lateral. No tubing was employed in these simulations. Instead the sink was placed on the opposite side of the model from the SAGD well pair. Thus the steam chamber wall is the closest part of the chamber to the sink, which ensures that the vent well will always be pulling from a NCG rich region. In selected embodiments, these wells could for example be drilled across an entire pad. In such an instance, the well may for example be provided with tubing having an inflow control device (ICD) placed halfway between the inter well space. In alternative embodiments, sections of the perpendicular vent wells may be selectively closed as the steam chamber grows and expands, so that the vent wells are only open in the regions near the steam chamber wall. To implement these and other alternative embodiments, a vent well may be operated to adjust its effective length and trajectory using blanks, ICDs, sliding sleeves or other means.

[00145] For simulations described in this section that contained a single perpendicular vent well, the vent well was placed between two points of steam injection, giving rise to four distinct gas vent well regions. A separate simulation was performed for each distinct vent well region. The exact location between each steam sub was selected based on the results of a sensitivity study performed on the four perpendicular vent well simulations. It will be appreciated that alternative placements are possible for single vent wells situated between steam injection points.

[00146] In simulations described herein having four simultaneous perpendicular vent wells, each well was located between steam injection points. In alternative embodiments, alternative perpendicular vent well locations may be selected, for

example so as to limit steam production and to maximize NCG production. In the embodiments described herein, all four vent wells were turned on at the same time, approximately one year into the SAGD operation.

[00147] **Figure 42** illustrates the impact on oil production of using four perpendicular vent wells simultaneously or utilizing a single perpendicular vent well between the various steam injection points. Inclusion of the vent wells dramatically improves oil production above that observed in the Base Case. Utilizing four vent wells simultaneously outperformed any singular vent well case, but the observed impact of utilizing more vent wells was disproportionate. Singular vent wells placed towards the middle of the SAGD well pair outperformed either of the single vent wells placed at the heel or toe.

[00148] **Figure 43** illustrates the significant reduction in 60% POIP recovery factor timing for the various perpendicular vent well cases. Utilizing four vent wells simultaneously achieved 60% POIP recovery factor timing much quicker than the Base Case or any singular vent well case. Again, the relationship between reductions in 60% POIP recovery factor timing to the number of vent wells in operation was disproportionately directly related. The improvement in oil recovery for the perpendicular vent well embodiments came at the expense of an increased cSOR.

[00149] **Figure 44** illustrates that the four simultaneous perpendicular vent well embodiment produced the most NCG. For the single perpendicular vent well embodiments, total gas production decreased as the vent well was moved further from the heel. The SAGD producer GORs were very different between cases. Vent wells near the heel of the producer may produce gas that would have been produced by the SAGD producer, which is reflected in the lower GORs. Vent wells placed near the toe of the producer did not impact gas production from the producer until later in the production schedule.

[00150] **Figures 45, 46, 47 and 48** illustrate that the use of perpendicular vent wells significantly improves SAGD performance in terms of oil production, days to 60%

POIP recovery factor and gas production. A small impact was observed on the cSOR, tied to the location of the vent well. Wells towards the toe of the SAGD well pair showed the greatest increase in cSOR. The four simultaneous perpendicular vent well embodiment showed the greatest increase in cSOR.

[00151] In the single perpendicular vent well embodiments, as was the case with the parallel vent well embodiments, little or no improvement in oil production is observed until the steam chamber connects with the vent well. This is because the vent well cannot vent any gas until this point. The delayed response between the various perpendicular vent well cases is due to the difference in vertical placement of the vent well between each case. For the cases where the vent well was located close to the toe of the SAGD well pair (GV-3 & GV-4), the vent well was placed much lower in the reservoir (10-15 m lower).

[00152] The information provided in **Figures 45 to 48** illustrates shows that when utilizing a singular perpendicular vent well, it may be optimal in some embodiments to locate the well towards the middle of the SAGD well pair (GV-2 & GV-3) in order to improve the time required to attain 60% POIP recovery factor . In the exemplified embodiments, these two locations reach 60% oil recovery earlier, and therefore have the highest sustained oil rates. Peak oil rates were up nearly 100% and the time required to reach blow was 4 years less when compared to the Base Case. These two locations also produced the most gas at 60% POIP recovery factor, while having a minimal impact on cSOR.

[00153] The mechanisms through which the perpendicular vent wells improve NCG production and therefore SAGD well pair performance involves the establishment or enhancement of an axial pressure gradient within the steam chamber that is parallel to the SAGD wellpair. This may be carried out in a manner that is dependent on the location of the well pair. For example, if the existing gradient is from toe to heel of the SAGD wellpair, placing a vent well at the heel would enhance the gradient, while placing one at the toe would reduce and reverse the gradient (**Figure 49**). This is for example illustrated by the fact that the vent well placed at the toe (GV-4) performed less well than a vent well placed at the heel (GV-1). GV-4 demonstrated relatively poor peak

oil production rates and achieved 60% POIP recovery factor timing just ahead of GV-1, despite GV-1 contacting the steam chamber 2.5 years later. GV-4 also demonstrated the greatest increase in cSOR. This may be the result of large drawdown between the neighboring injection sources and the vent well, and a relatively poor gradient across most of the well, so that steam is preferentially produced over NCG.

[00154] The relative magnitude of the axial pressure gradient plays an important role in adjusting the difference in performance between perpendicular vent wells located towards the middle of the SAGD well pair and those located at the heel or toe. **Figure 50** illustrates that at their peak rates, GV-1 and GV-2 have a similar magnitude pressure drop between the highest and lowest pressure points. The placement of GV-2 causes the gradient to be concentrated over a slightly shorter distance, but still very productive portion of the well. The larger pressure gradient results in higher NCG *in situ* velocity; while the well placement reduces the distance gas must travel to access a production source. Combing the two, results in a reduced NCG resonance time and therefore higher temperatures at the chamber wall. As the vent well moves further towards the toe, this gradient becomes concentrated over a smaller portion of the well. This reduces the resonance time for a smaller proportion of the NCG, leading to the preferential production of steam, so that increasing cSOR values are observed as the vent well is moved closer to the toe.

[00155] This example illustrates that alternative vent well placements may have a significant impact on reservoir performance. In addition to location, the orientation of the vent well, in these examples perpendicular to the SAGD well pair, is also adjustable so as to improve performance. A perpendicular vent well may be located and oriented so that at least some portion of the vent well is always in contact with the bitumen/steam interface where NCGs tend to accumulate. Continually contacting this region helps to improve efficiency in producing NCGs. Also, completing the vent well in a manner that ensures that production is from the bitumen side of the interface may help to ensure that the point of maximum drawdown for the vent well will be at the interface, the area with the greatest likelihood of containing NCGs. Similarly, the orientation of the vent well

may be adjusted to help to minimize the exposure of the vent well to the steam chamber, thus concentrating drawdown in a smaller region.

Longitudinally Truncated and Laterally Deviated Vent Wells

[00156] In alternative embodiments, aspects of the invention involve the use of vent wells in which the longitudinal axial dimension of the vent well above a SAGD well pair is truncated, and this truncation may be by way of a deviated lateral strike, so that the vent well deviates from an initial trajectory that is in the vertical plane of an underlying SAGD well pair, and thereafter adopts a strike that departs laterally from the longitudinal axial dimension of the SADG well pair. In selected embodiments, this deviated lateral strike may extend laterally across two or more well pairs, in effect providing a shared vent well that services two or more adjoining steam chambers.

[00157] In an illustrative embodiment, a truncated vent well was modeled running parallel to a corresponding SAGD well pair for 75 m, with the vent well elevated within the reservoir so that it is located 5.5 m below the top of the reservoir and directly above the much longer SAGD well pair. In an alternative variant, this elevated vent segment is truncated by a lateral deviation from the vertical plane of the SADG well pair at a selected point. The vent well trajectory following the deviation remained at a constant elevation 5.5 m from the top of the reservoir. In these embodiments, production of NCGs by the vent well was through a tubing string open at the toe.

[00158] As illustrated in **Figures 51**, in terms of oil production both the truncated, elevated vent well and the deviated vent well show improvements over the Base Case and the centrally located parallel vent well (the 225 m Selectively Slotted vent well described above). It is evident that there is some delay in the steam chamber contacting these vent wells, due to the elevated location of both vent wells in the reservoir. **Figure 52** illustrates a significant improvement in the time to achieve 60% recovery factor (blow down) with no meaningful impact on cSOR, for both embodiments. Both these vent wells work to enhance an existing axial NCG pressure gradient within the steam chamber, helping to mobilize NCGs for production.

[00159] In an alternative embodiment, a deviated vent well may extend laterally, so as to intersect two or more steam chambers, in a manner similar to a perpendicular vent well. In an exemplified embodiment, as illustrated in **Figure 53**, performance of each well pair ("Deviated #1" and "Deviated #2") was improved over the Base Case well. Well pair 1 ("Deviated #1"), located where the vent well originates, performed better than well pair 2 ("Deviated #2"). In this embodiment, as illustrated in **Figure 54**, utilizing the deviated vent well located over two well pairs results in improved oil production rates over the Base Case for both well pairs and an accelerated blow down date (60% Recovery Factor), with little impact on the cSOR (increase of 0.2).

Conclusion

[00160] Although various embodiments of the invention are disclosed herein, many adaptations and modifications may be made within the scope of the invention in accordance with the common general knowledge of those skilled in this art. For example, any one or more of the injection, production or vent wells may be adapted from well segments that have served or serve a different purpose, so that the well segment may be re-purposed to carry out aspects of the invention, including for example the use of multilateral wells as injection, production and/or vent wells. Such modifications include the substitution of known equivalents for any aspect of the invention in order to achieve the same result in substantially the same way. Numeric ranges are inclusive of the numbers defining the range. The word "comprising" is used herein as an open-ended term, substantially equivalent to the phrase "including, but not limited to", and the word "comprises" has a corresponding meaning. As used herein, the singular forms "a", "an" and "the" include plural referents unless the context clearly dictates otherwise. Thus, for example, reference to "a thing" includes more than one such thing. Citation of references herein is not an admission that such references are prior art to the present invention. Any priority document(s) and all publications, including but not limited to patents and patent applications, cited in this specification are incorporated herein by reference as if each individual publication were specifically and individually indicated to be incorporated by reference herein and as though fully set forth

herein. The invention includes all embodiments and variations substantially as hereinbefore described and with reference to the examples and drawings.

CLAIMS

1. A process for removing fluids from a subterranean formation, the process comprising:

a) selecting a hydrocarbon reservoir in the formation bearing a heavy oil, the reservoir comprising a steam chamber having a peripheral zone comprising condensing steam, non-condensing gas and mobile hydrocarbons, wherein the steam chamber has a longitudinal axial dimension formed by:

i) a generally horizontal segment of a production well that is in fluid communication with the zone of mobile hydrocarbons;

ii) a generally horizontal segment of an injection well that is in fluid communication with the steam chamber, generally parallel to and vertically spaced apart above the horizontal segment of the production well; and;

b) injecting an injection fluid comprising steam through the horizontal segment of the injection well at a range of selected bottom hole injection pressures that vary between steam injection points that are spaced apart along the length of the horizontal segment of the injection well, so as to form an axial pressure gradient within the steam chamber from a high pressure region to a low pressure region, so as to concurrently:

i) mobilize the heavy oil in the peripheral zone to form the mobile hydrocarbons, so that the mobile hydrocarbons flow downwardly and towards the production well in a gravity dominated process;

ii) mobilize the non-condensing gas in the peripheral zone, so that the non-condensing gas flows in the axial dimension of the steam chamber in a convective flow motivated by the axial pressure gradient, moving from the high pressure region to the low pressure region; and,

iii) radially expand the steam chamber; and,

c) arranging the steam injection points and one or more gas production points so that the non-condensing gas is preferentially delivered to a non-condensing gas production region of the formation that resides in the low pressure region of the axial pressure gradient and comprises one or more of the gas production points; and,

d) recovering the mobilized hydrocarbons and non-condensing gas from the reservoir through one or more wells in the formation, thereby removing heavy oil and non-condensing gases from the reservoir.

2. The process of claim 1, wherein arranging the steam injection points comprises adjusting the relative vertical position of steam injection points along the injection well.

3. The process of claim 1 or 2, wherein arranging the steam injection points comprises adjusting the relative horizontal position of steam injection points along the injection well.

4. The process of any one of claims 1 to 3, wherein the injection well and production well each comprise:

a heel segment that is proximal to a vertical segment of the well that connects the horizontal segment of the well to a surface completion; and,

a toe segment that is spaced apart from the heel by the horizontal segment of the well.

5. The process of claim 4, wherein the production well comprises one or more of the gas production points in a non-condensing gas production region of the production well, and the non-condensing gas production region of the production well is proximal to the heel segment of the production well.

6. The process of claim 5, wherein the intermediate casing point of the injector well is landed at a shallow angle so as to increase the vertical spacing between the heel of the injector well and the heel of the producer well.

7. The process of claim 4, wherein the production well comprises one or more of the gas production points in a non-condensing gas production region of the production well, and the non-condensing gas production region of the production well is proximal to the toe segment of the production well.

8. The process of claim 4, wherein the production well comprises one or more of the gas production points in a non-condensing gas production region of the production well, and the non-condensing gas production region of the production well is intermediately spaced apart from the heel segment of the production well and the toe segment of the production well.

9. The process of claim 4, wherein the injection well has a sinusoidal trajectory in longitudinal cross section, with high points at the heel of the injection well and between points of steam egress from an injector tubing into an annulus between the injector tubing and an injector casing.

10. The process of any one of claims 1 to 9, further comprising:

providing a vent well in the reservoir in fluid communication with the steam chamber, the vent well comprising one or more of the gas production points; and,

producing non-condensing gases from the vent well so as to amplify the axial pressure gradient within the steam chamber.

11. The process of any one of claims 1 through 9, wherein one or both of the injection or production well is a segment of a multilateral well.

12. The process of claim 10, wherein the vent well is a segment of a multilateral well.

13. The process of claim 10 or 12, wherein the vent well is a truncated well having a longitudinal vent well dimension that is less than the longitudinal axial dimension of the horizontal segments of the injection and production wells.

14. A process for removing fluids from a subterranean formation, the process comprising:

a) selecting a hydrocarbon reservoir in the formation bearing a heavy oil, the reservoir comprising a steam chamber having a peripheral zone comprising condensing steam, non-condensing gas and mobile hydrocarbons, wherein the steam chamber has a longitudinal axial dimension formed by:

i) a generally horizontal segment of a single well that is in fluid communication with the zone of mobile hydrocarbons with the steam chamber;

b) injecting an injection fluid comprising steam through the horizontal segment of the single well at a range of selected bottom hole injection pressures that vary between steam injection points that are spaced apart along the length of the horizontal segment of the single well, so as to form an axial pressure gradient within the steam chamber from a high pressure region to a low pressure region, so as to concurrently:

i) mobilize the heavy oil in the peripheral zone to form the mobile hydrocarbons, so that the mobile hydrocarbons flow downwardly and towards the single well in a gravity dominated process;

ii) mobilize the non-condensing gas in the peripheral zone, so that the non-condensing gas flows in the axial dimension of the steam chamber in a convective flow motivated by the axial pressure gradient, moving from the high pressure region to the low pressure region; and,

iii) radially expand the steam chamber; and,

c) arranging the steam injection points and one or more gas production points so that the non-condensing gas is preferentially delivered to a non-condensing gas production region of the formation that resides in the low pressure region of the axial pressure gradient and comprises one or more of the gas production points; and,

d) recovering the mobilized hydrocarbons and non-condensing gas from the reservoir through one or more wells in the formation, thereby removing heavy oil and non-condensing gases from the reservoir.

15. The process of claim 14, wherein the single well comprises both an injection means and a production means.

16. The process of claim 14, the single well is operated in alternating injection and production modes.

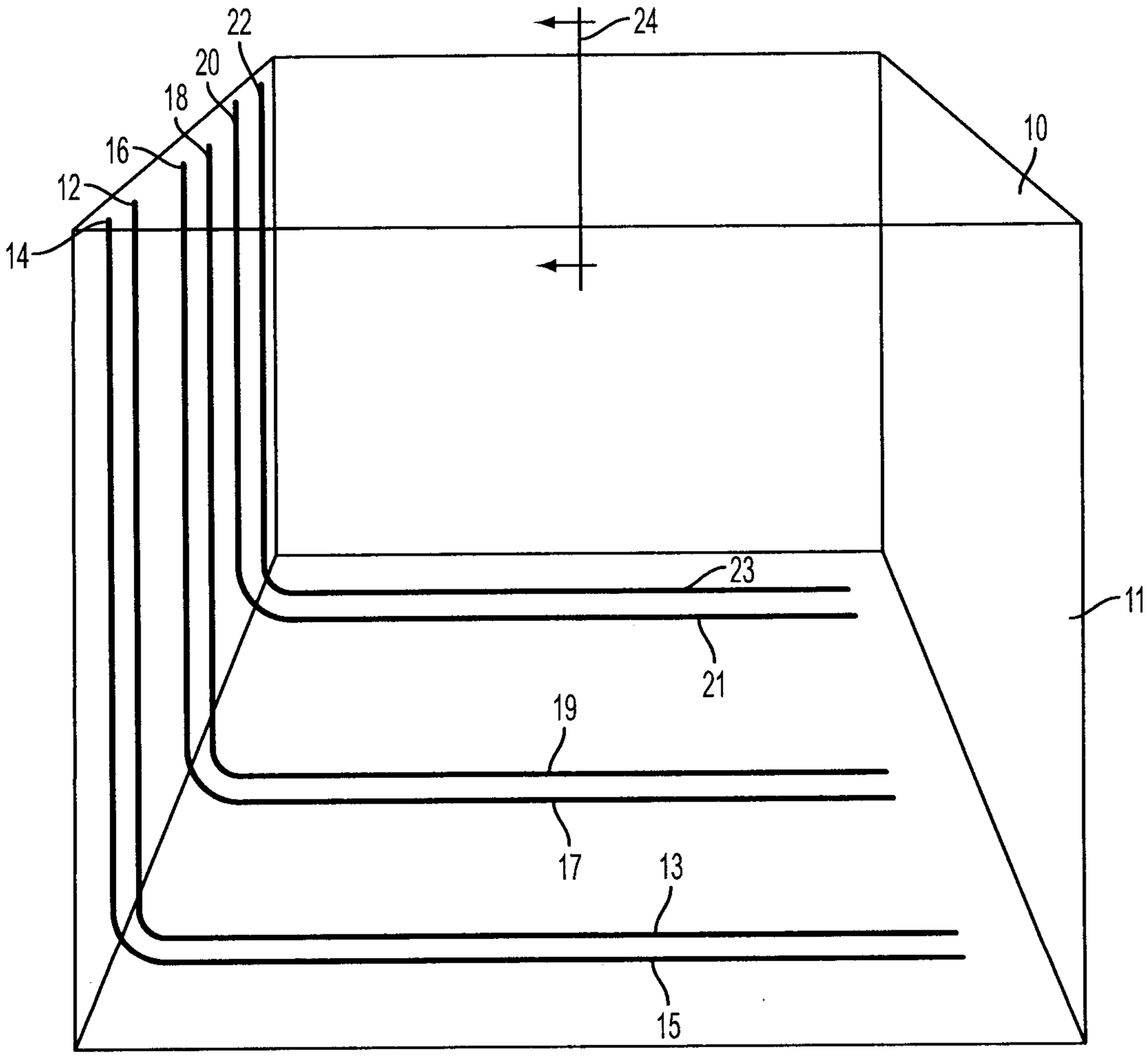


FIG. 1

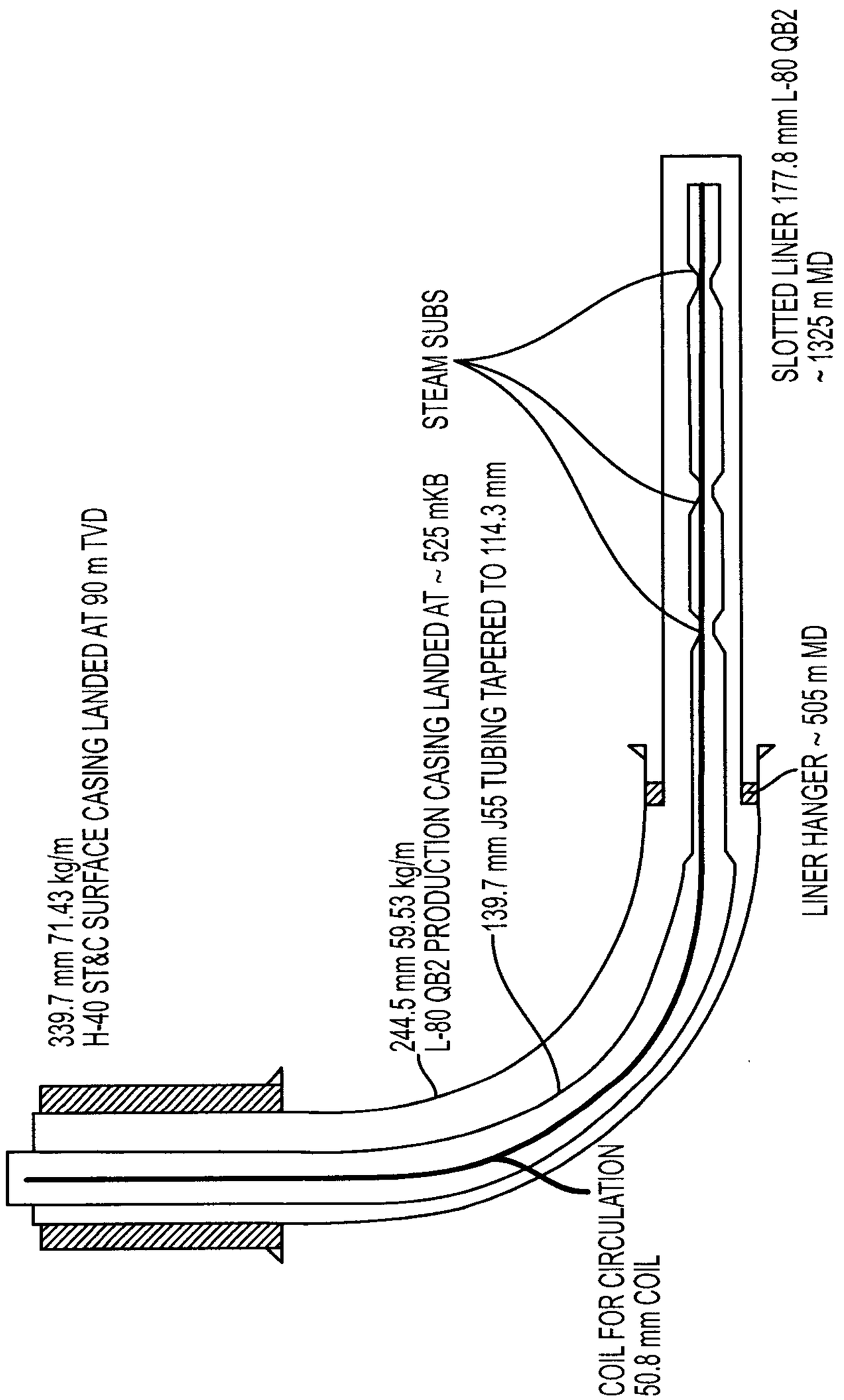

339.7 mm 71.43 kg/m
H-40 ST&C SURFACE CASING LANDED AT 90 m TVD
244.5 mm 59.53 kg/m
L-80 QB2 PRODUCTION CASING LANDED AT ~ 525 mKB
139.7 mm J55 TUBING TAPERED TO 114.3 mm
STEAM SUBS
SLOTTED LINER 177.8 mm L-80 QB2
~ 1325 m MD
LINER HANGER ~ 505 m MD
COIL FOR CIRCULATION
50.8 mm COIL

FIG. 2

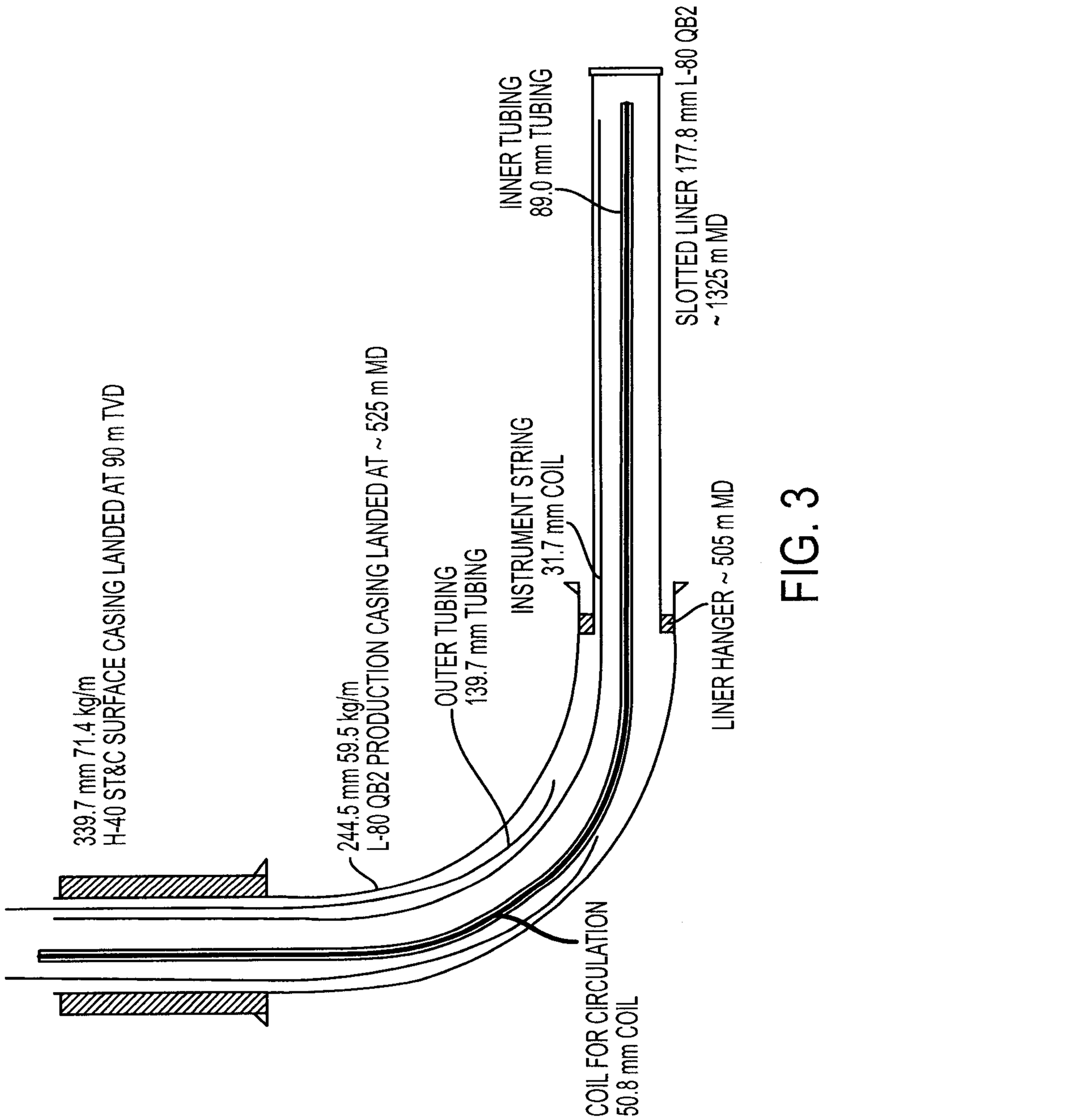

339.7 mm 71.4 kg/m
H-40 ST&C SURFACE CASING LANDED AT 90 m TVD
244.5 mm 59.5 kg/m
L-80 QB2 PRODUCTION CASING LANDED AT ~ 525 m MD
OUTER TUBING
139.7 mm TUBING
INNER TUBING
89.0 mm TUBING
INSTRUMENT STRING
31.7 mm COIL
SLOTTED LINER 177.8 mm L-80 QB2
~ 1325 m MD
LINER HANGER ~ 505 m MD
COIL FOR CIRCULATION
50.8 mm COIL

FIG. 3

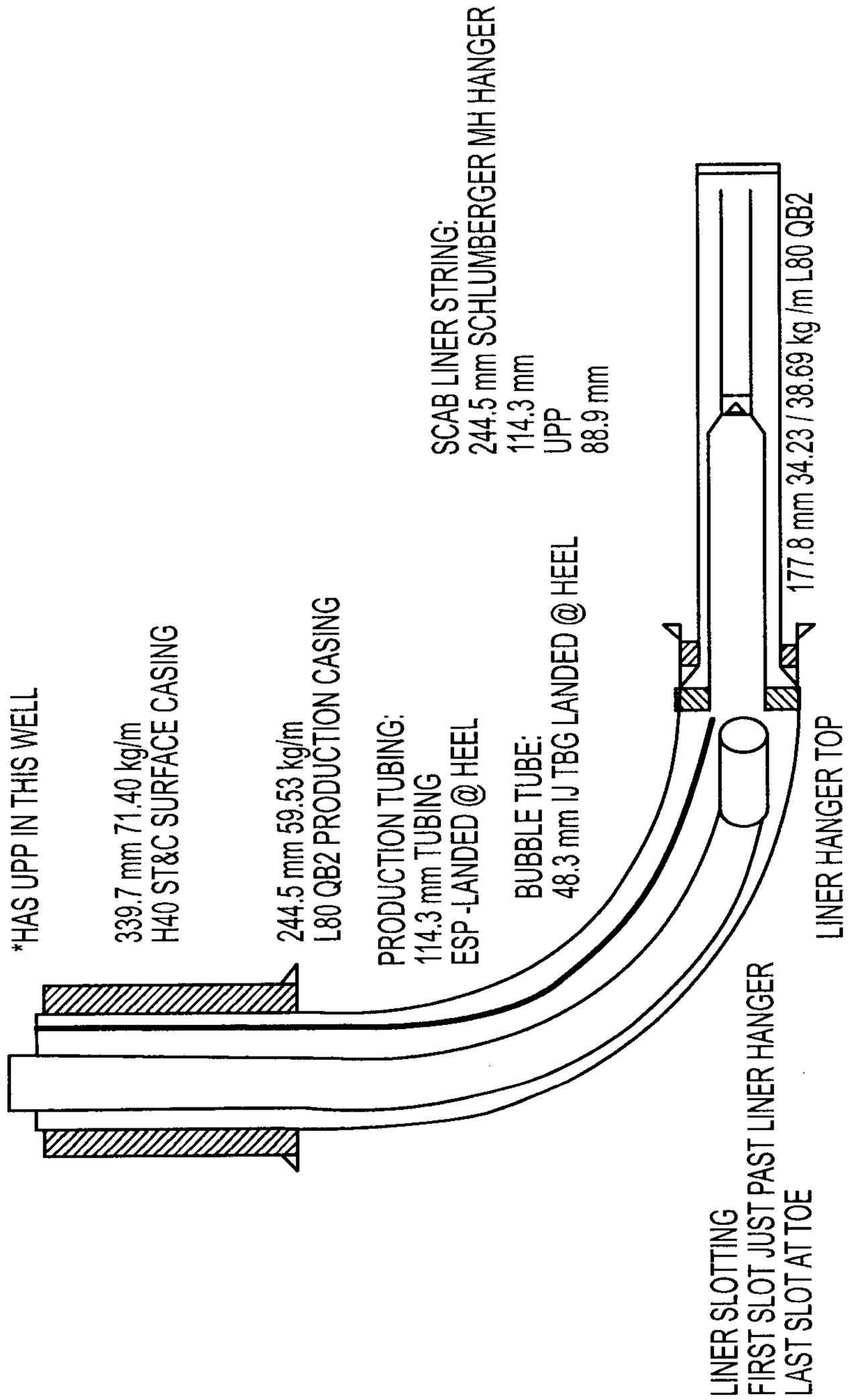

*HAS UPP IN THIS WELL
339.7 mm 71.40 kg/m
H40 ST&C SURFACE CASING
244.5 mm 59.53 kg/m
L80 QB2 PRODUCTION CASING
PRODUCTION TUBING:
114.3 mm TUBING
ESP -LANDED @ HEEL
BUBBLE TUBE:
48.3 mm IJ TBG LANDED @ HEEL
SCAB LINER STRING:
244.5 mm SCHLUMBERGER
114.3 mm
UPP
88.9 mm
177.8 mm 34.23 / 38.69 kg /m L80 QB2
LINER HANGER TOP
LINER SLOTTING
FIRST SLOT JUST PAST LINER HANGER
LAST SLOT AT TOE
MH HANGER

FIG. 4a

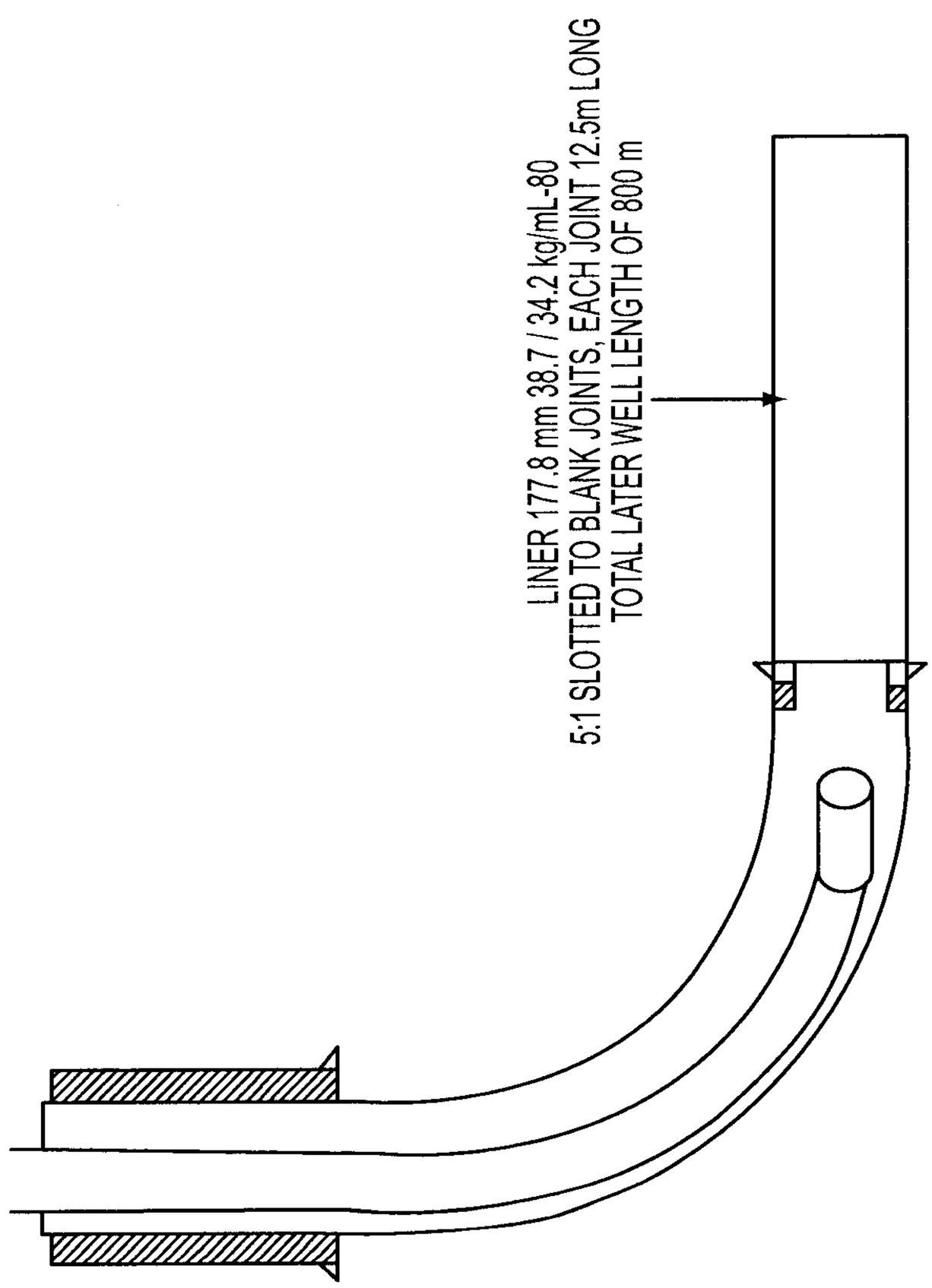

LINER 177.8 mm 38.7 / 34.2 kg/mL-80
5:1 SLOTTED TO BLANK JOINTS, EACH JOINT 12.5 m LONG
TOTAL LATER WELL LENGTH OF 800 m

FIG. 4b

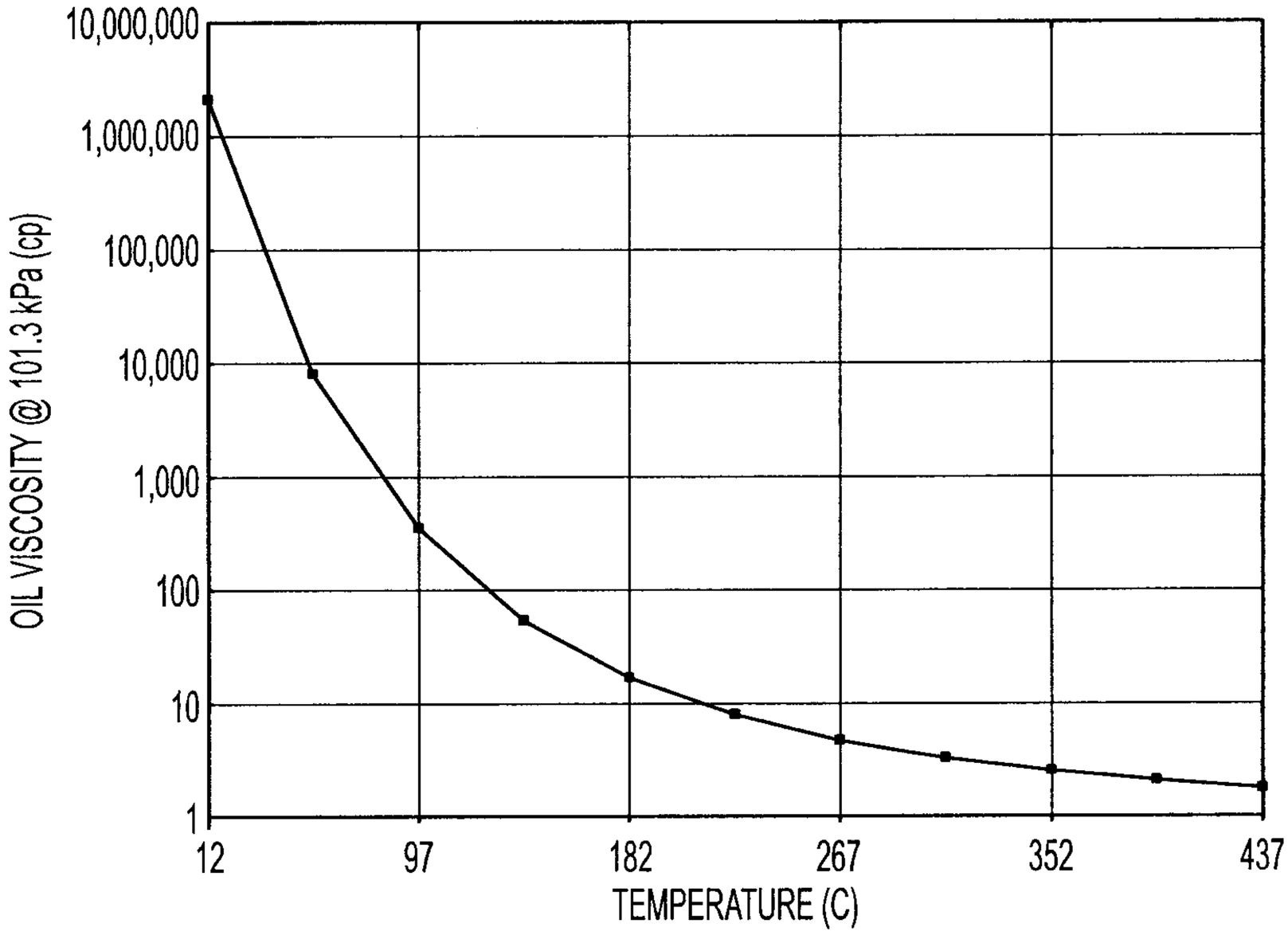

10,000,000
1,000,000
100,000
10,000
1,000
100
10
1
OIL VISCOSITY @ 101.3 kPa (cp)
12
97
182
267
352
437
TEMPERATURE (C)

FIG. 5

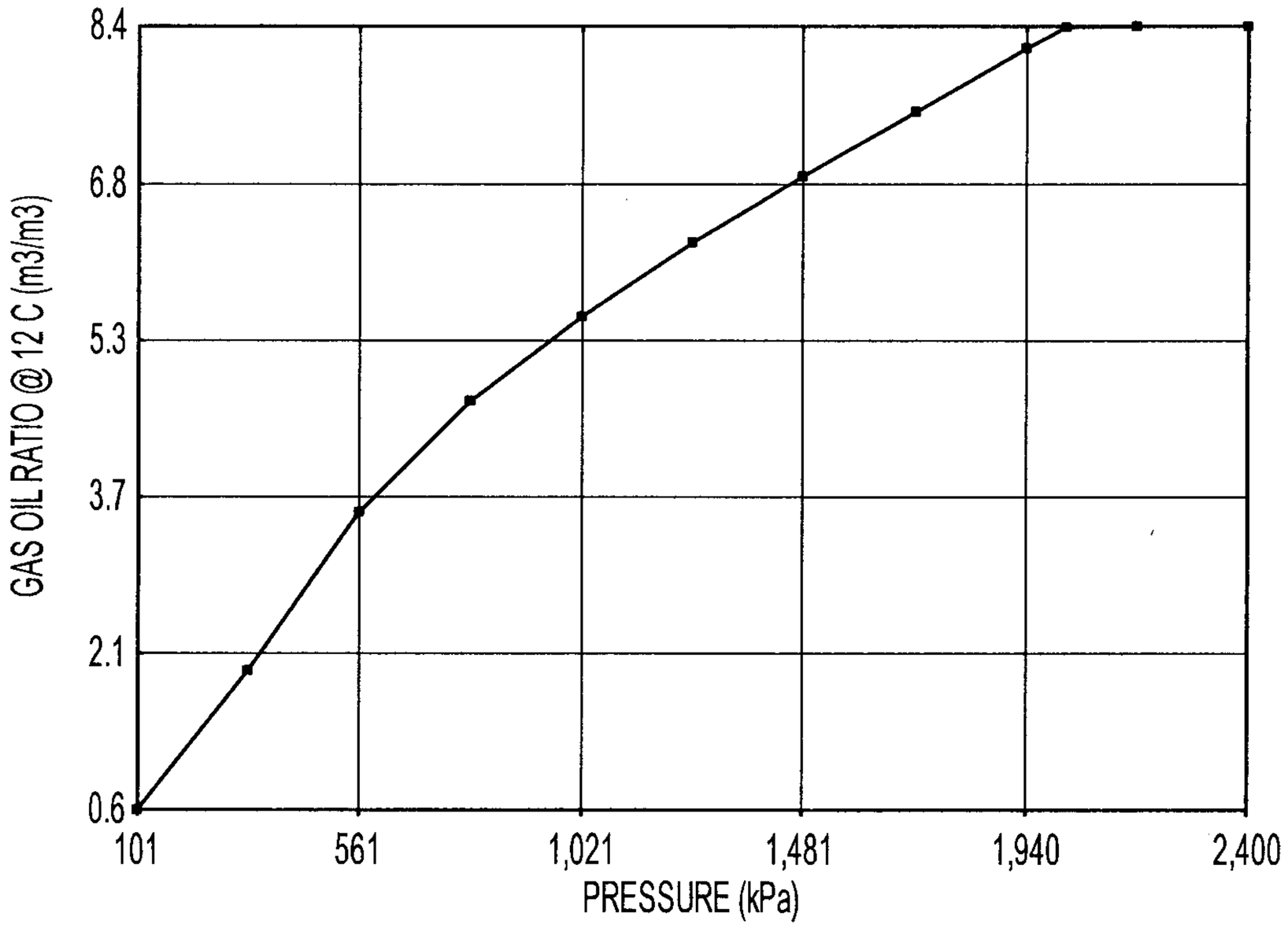

GAS OIL RATIO @ 12 C (m3/m3)
8.4
6.8
5.3
3.7
2.1
0.6
101
561
1,021
1,481
1,940
2,400
PRESSURE (kPa)

FIG. 6

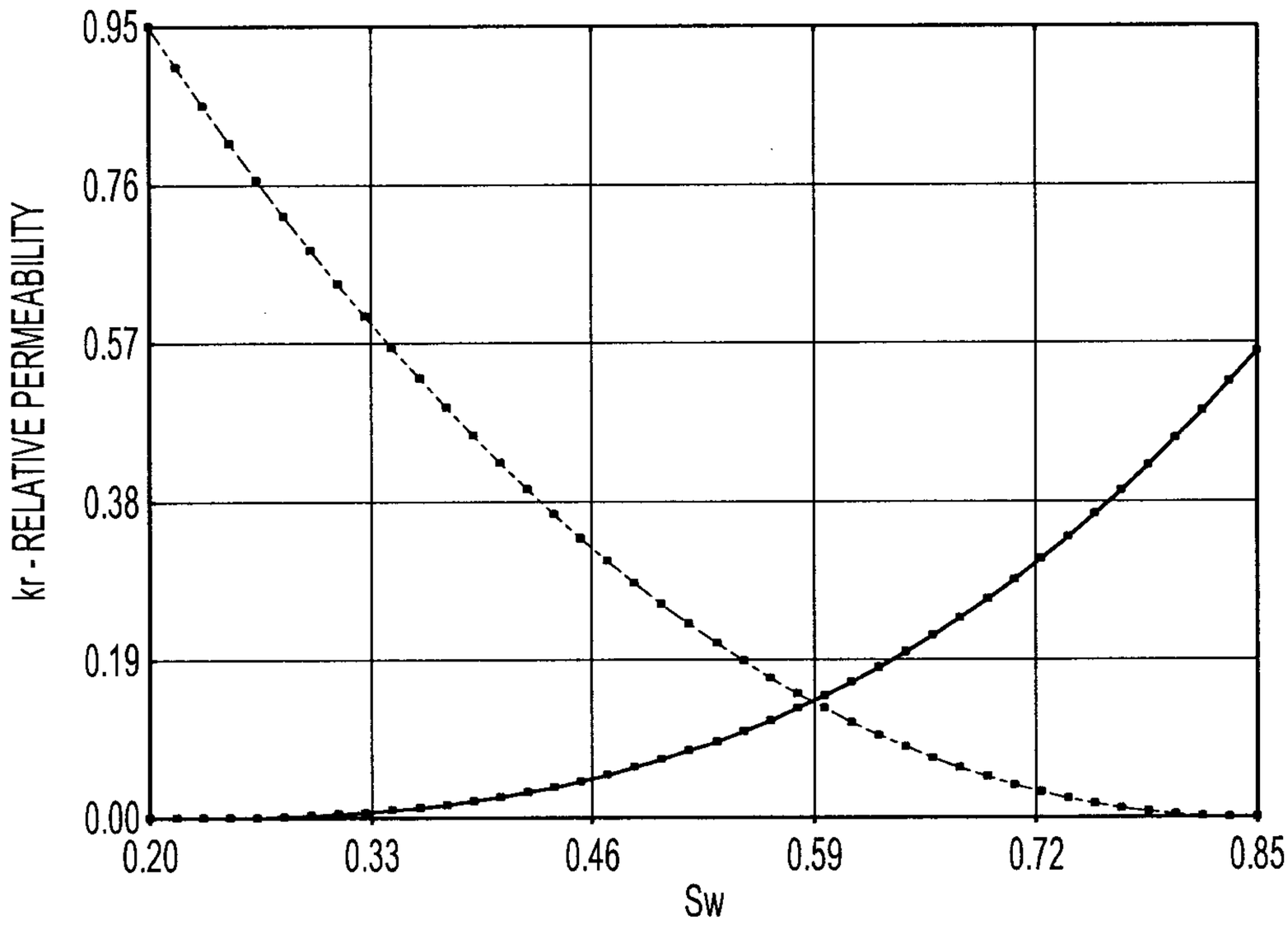

0.95
0.76
0.57
0.38
0.19
0.00
kr - RELATIVE PERMEABILITY
0.20
0.33
0.46
0.59
0.72
0.85
Sw

FIG. 7

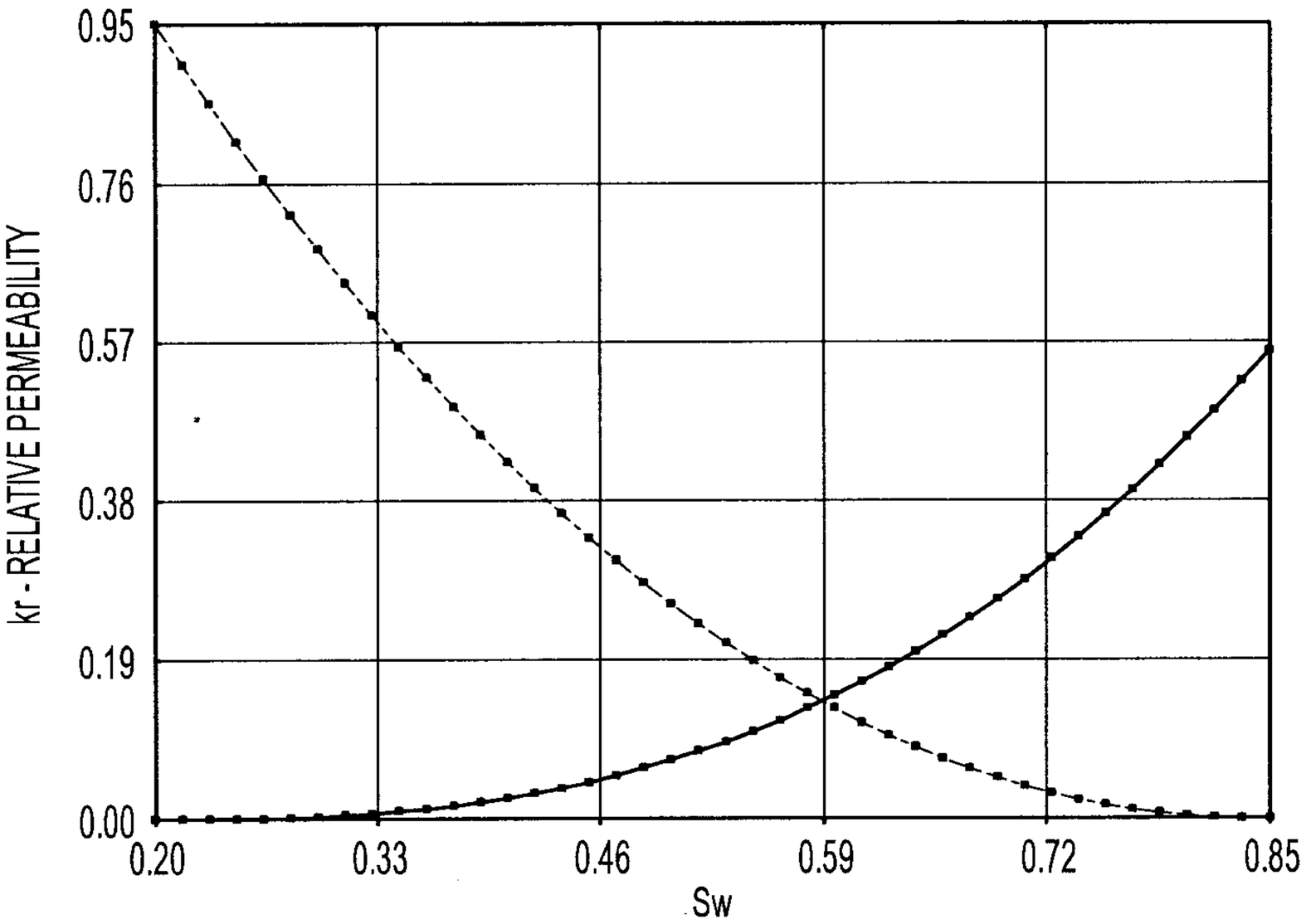

0.95
0.76
0.57
0.38
0.19
0.00
kr - RELATIVE PERMEABILITY
0.20
0.33
0.46
0.59
0.72
0.85
Sw

FIG. 8

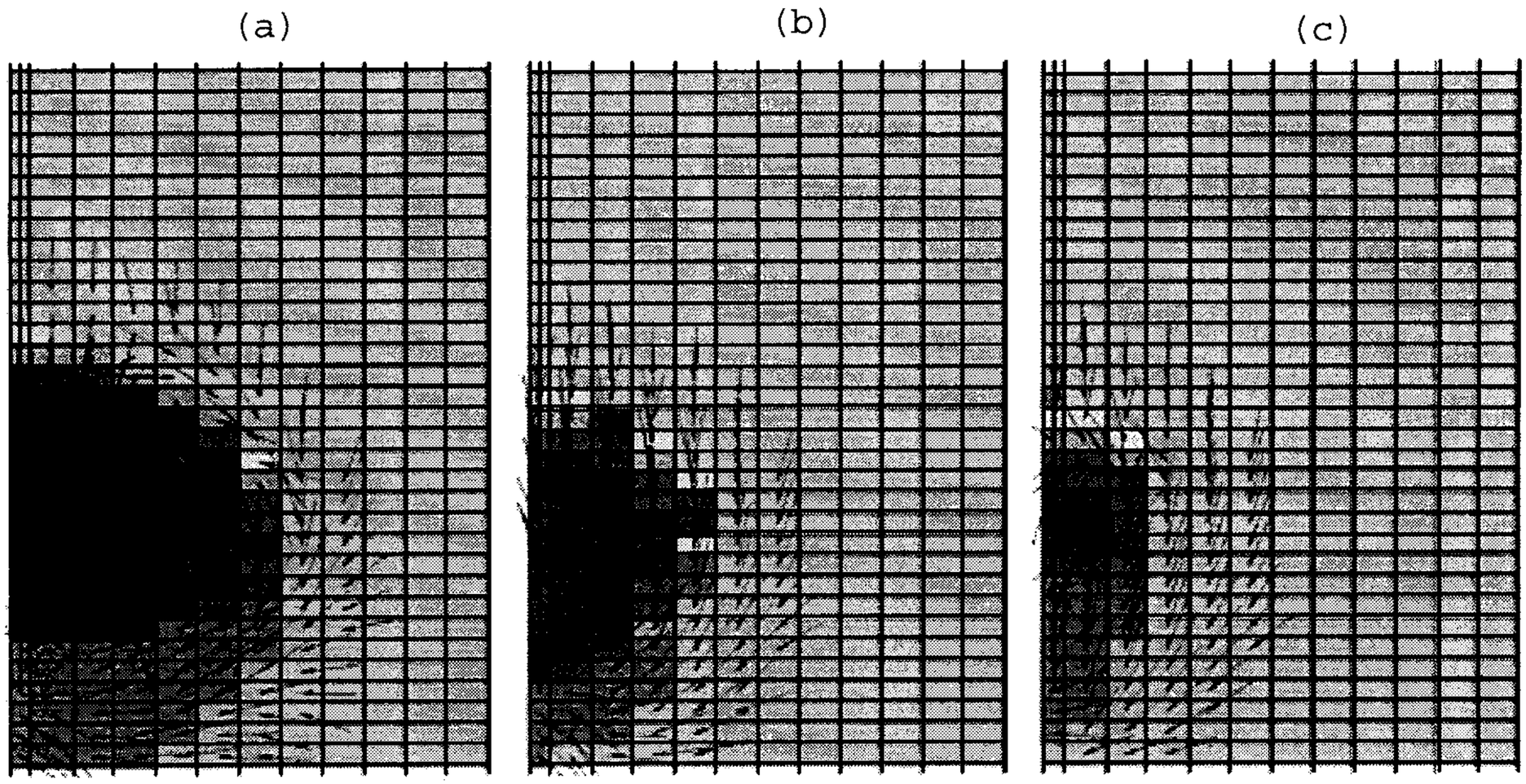


FIG. 9

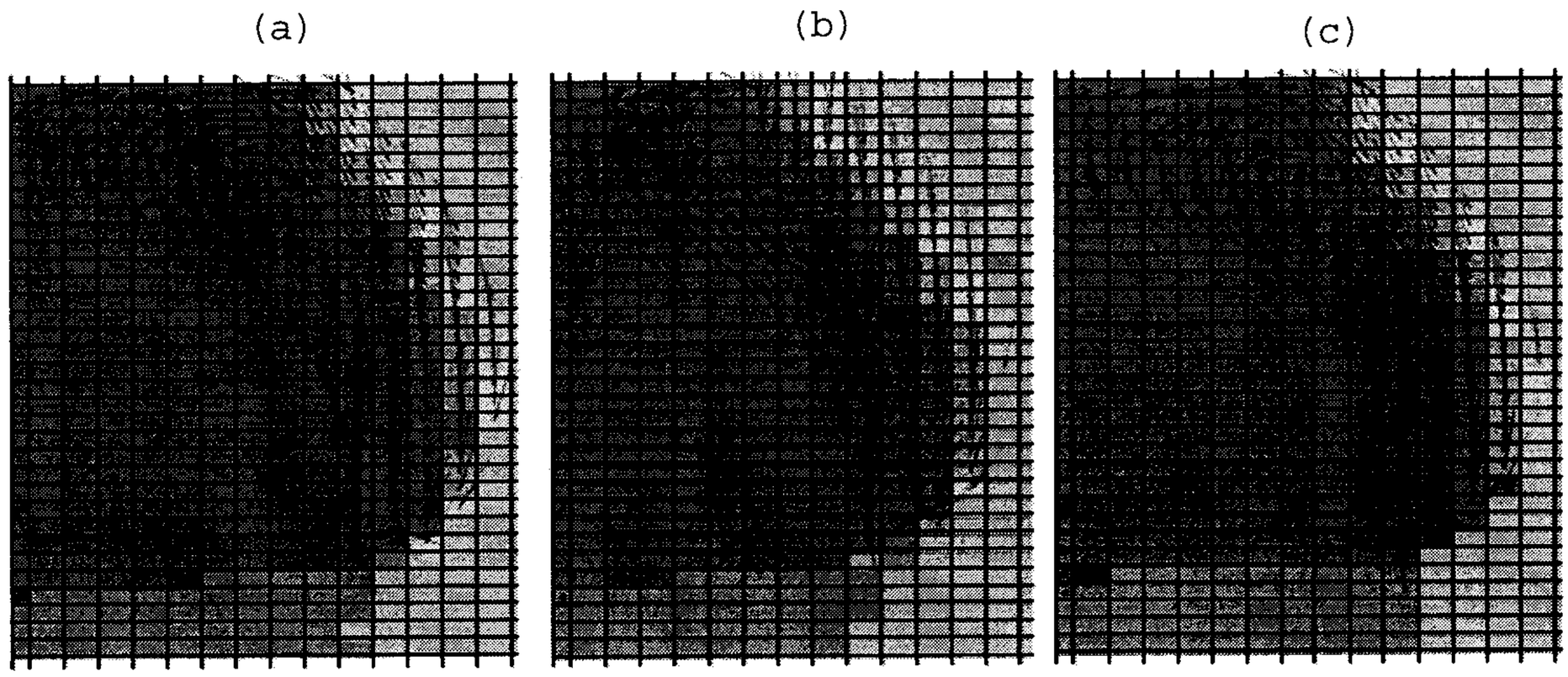


FIG. 10

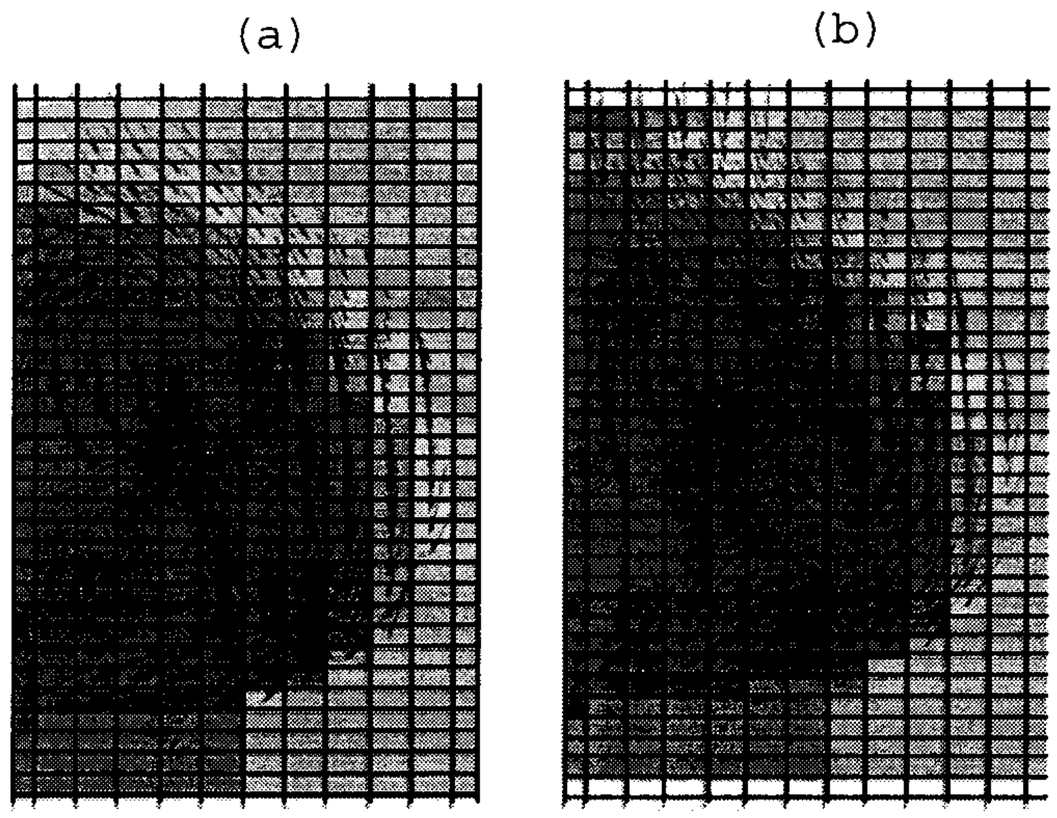


FIG. 11

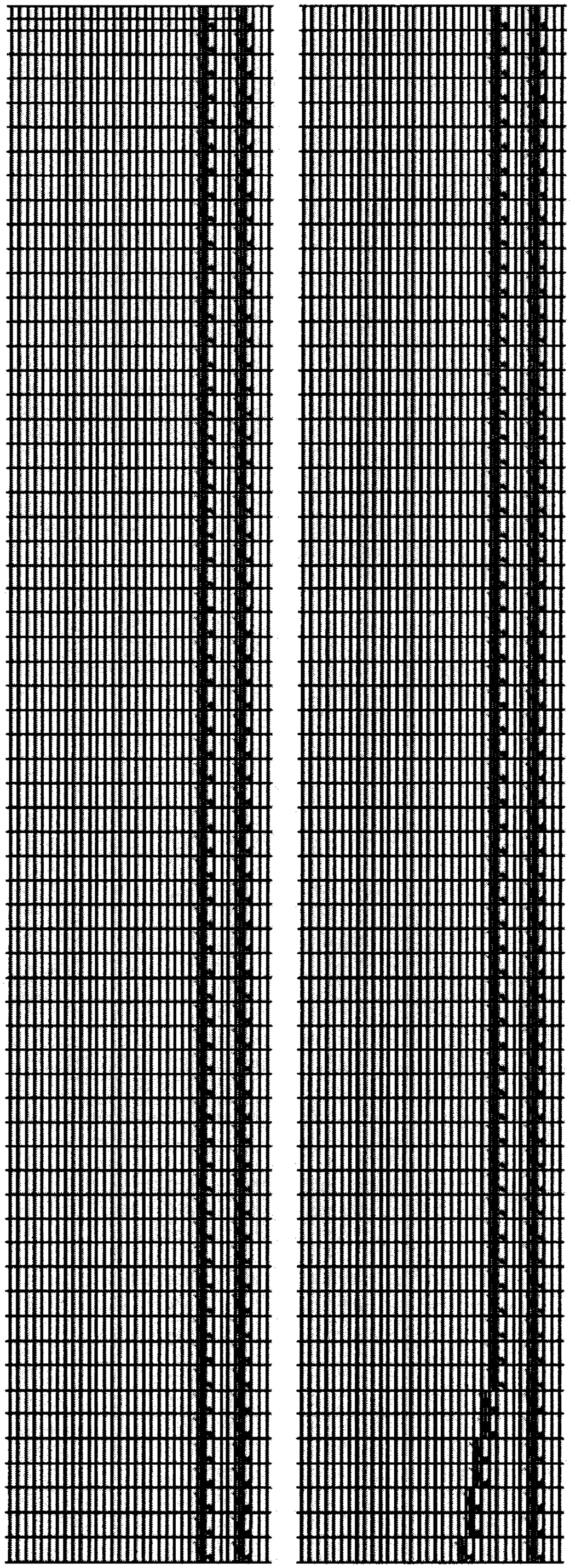


FIG. 12

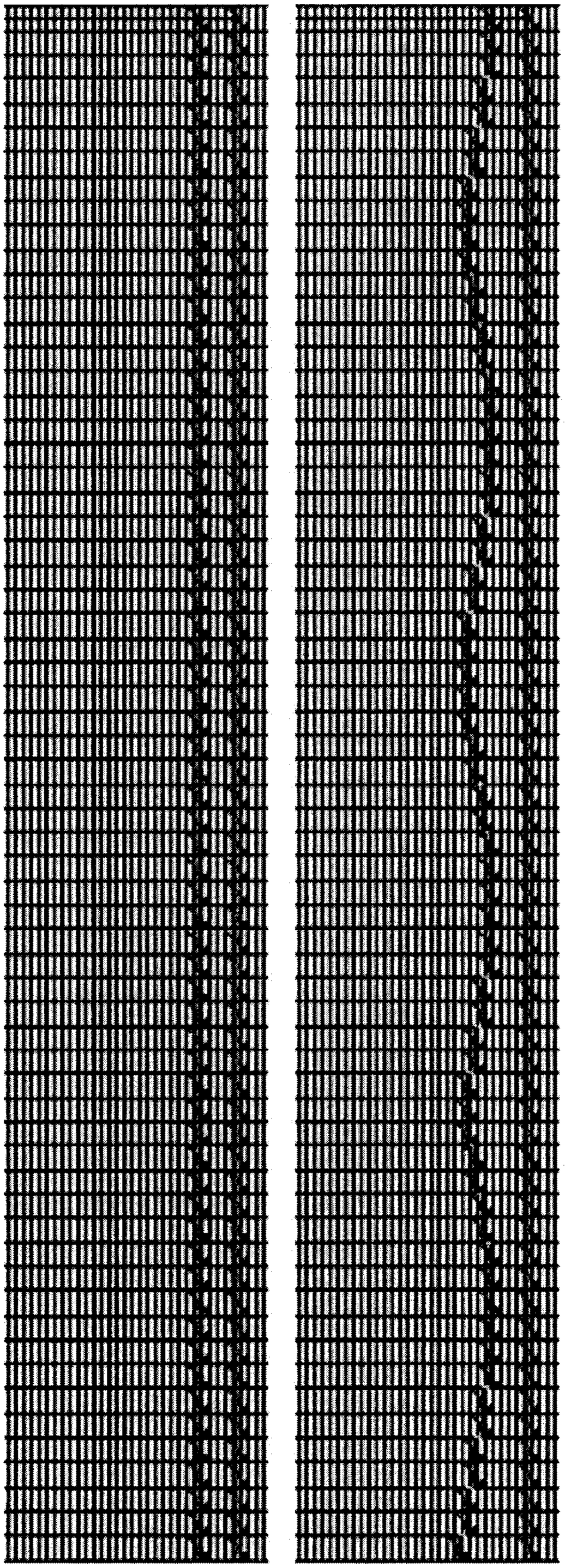


FIG. 13

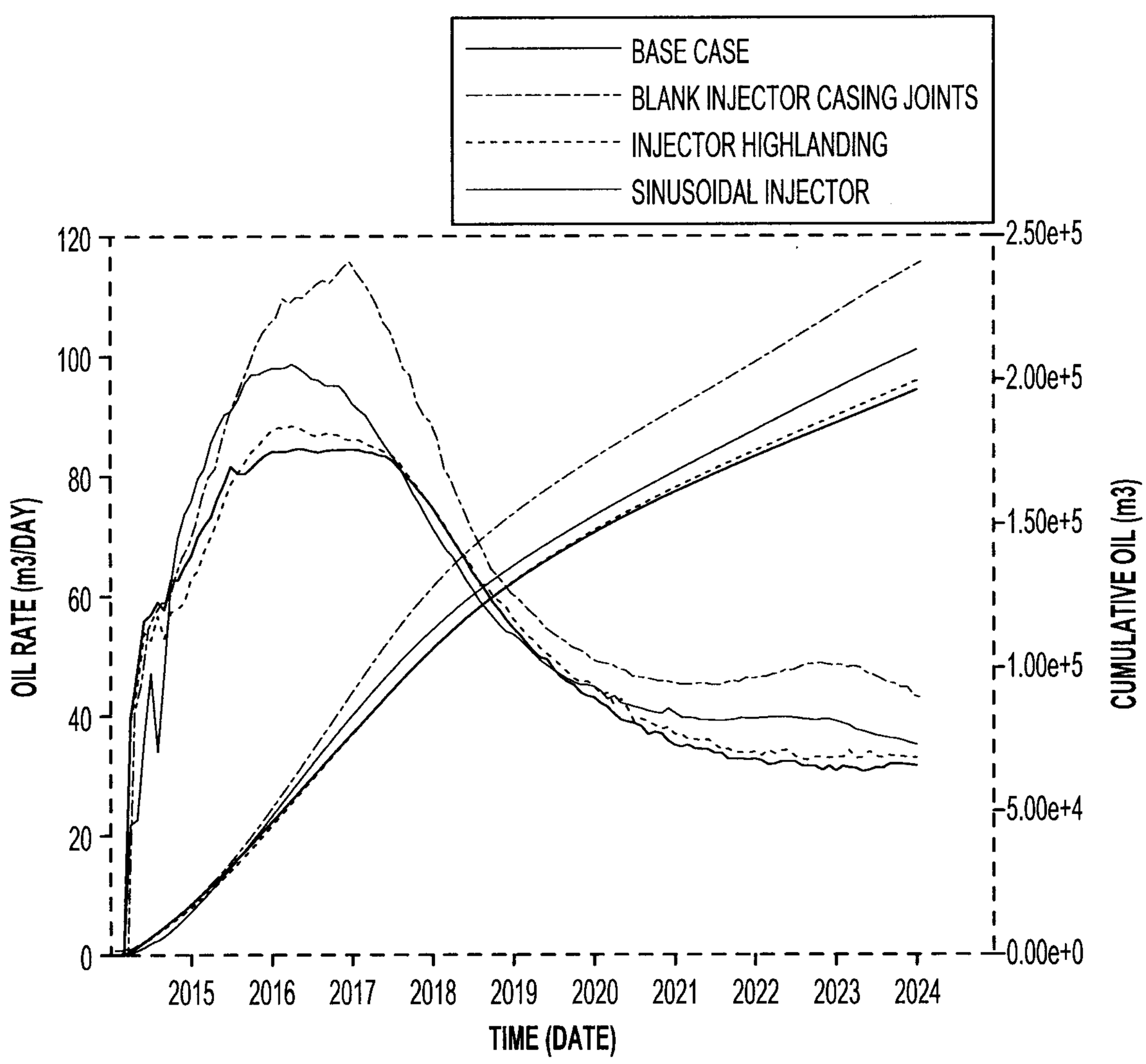

BASE CASE
BLANK INJECTOR CASING JOINTS
INJECTOR HIGHLANDING
SINUSOIDAL INJECTOR
OIL RATE (m3/DAY)
CUMULATIVE OIL (m3)
120
100
80
60
40
20
0
2.50e+5
2.00e+5
1.50e+5
1.00e+5
5.00e+4
0.00e+0
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
TIME (DATE)

FIG. 14

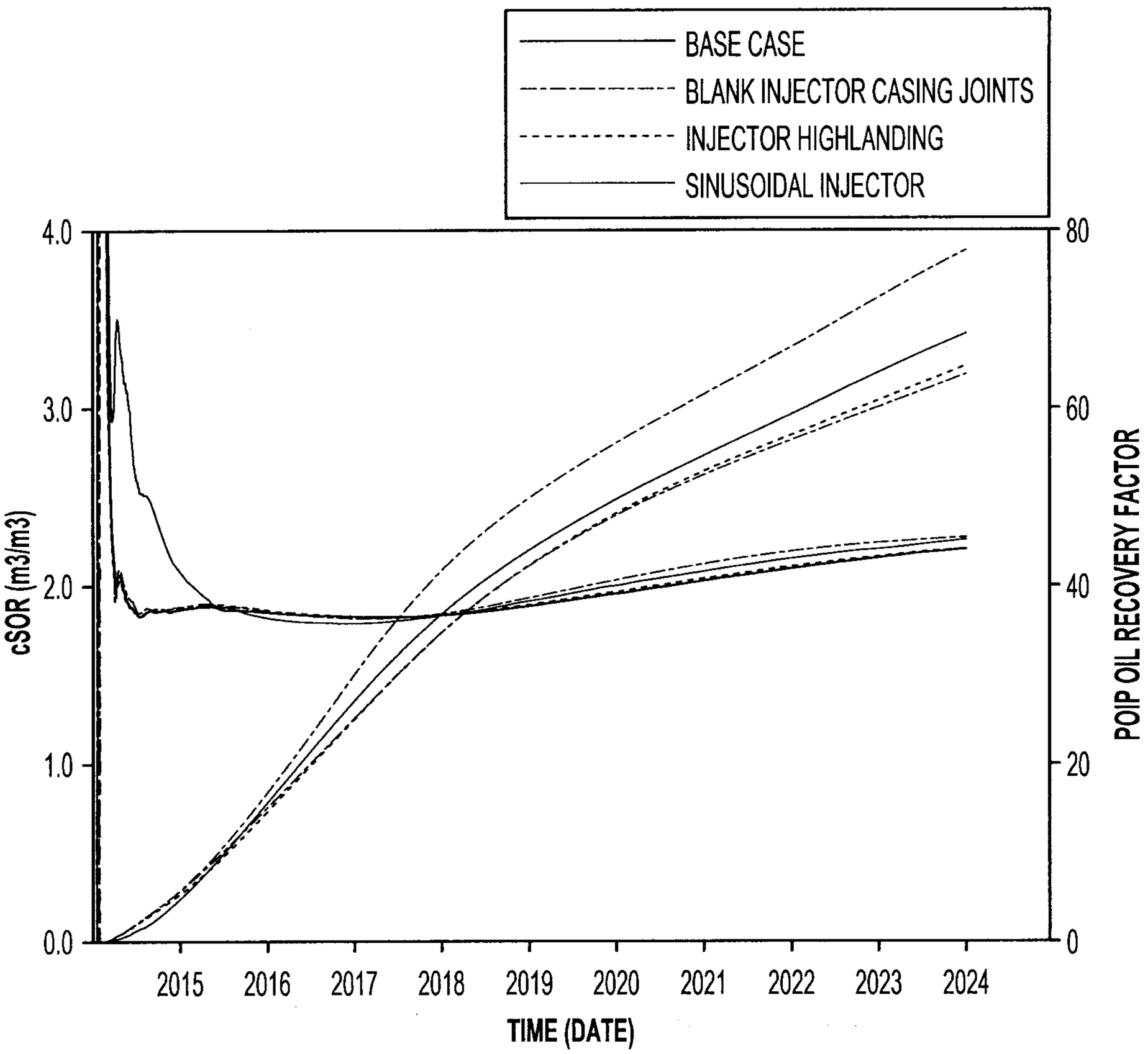

BASE CASE
BLANK INJECTOR CASING JOINTS
INJECTOR HIGHLANDING
SINUSOIDAL INJECTOR
4.0
3.0
2.0
1.0
0.0
cSOR (m3/m3)
80
60
40
20
0
POIP OIL RECOVERY FACTOR
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
TIME (DATE)

FIG. 15

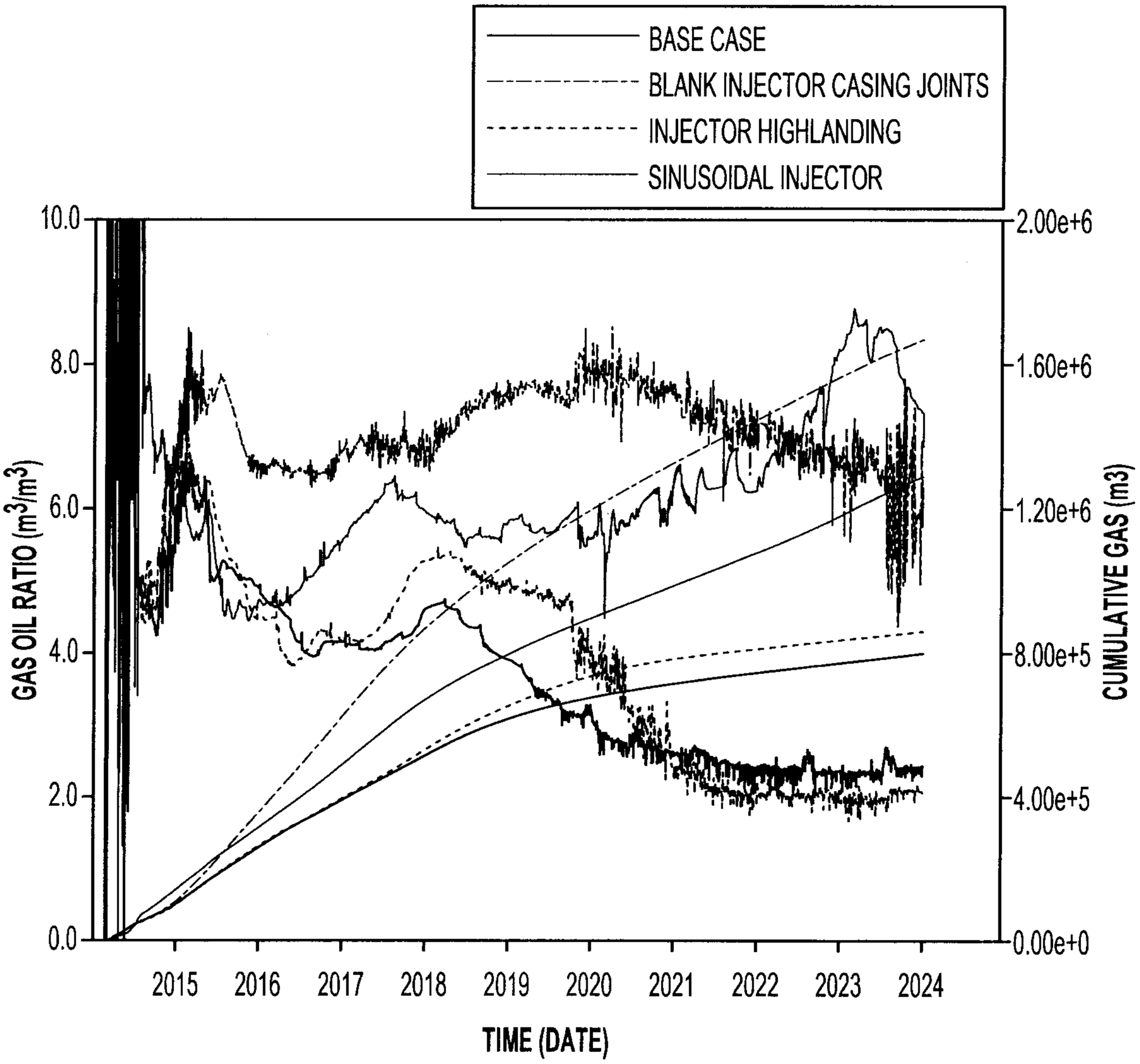

BASE CASE
BLANK INJECTOR CASING JOINTS
INJECTOR HIGHLANDING
SINUSOIDAL INJECTOR
10.0
8.0
6.0
4.0
2.0
0.0
GAS OIL RATIO (m3/m3)
2.00e+6
1.60e+6
1.20e+6
8.00e+5
4.00e+5
0.00e+0
CUMULATIVE GAS (m3)
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
TIME (DATE)

FIG. 16

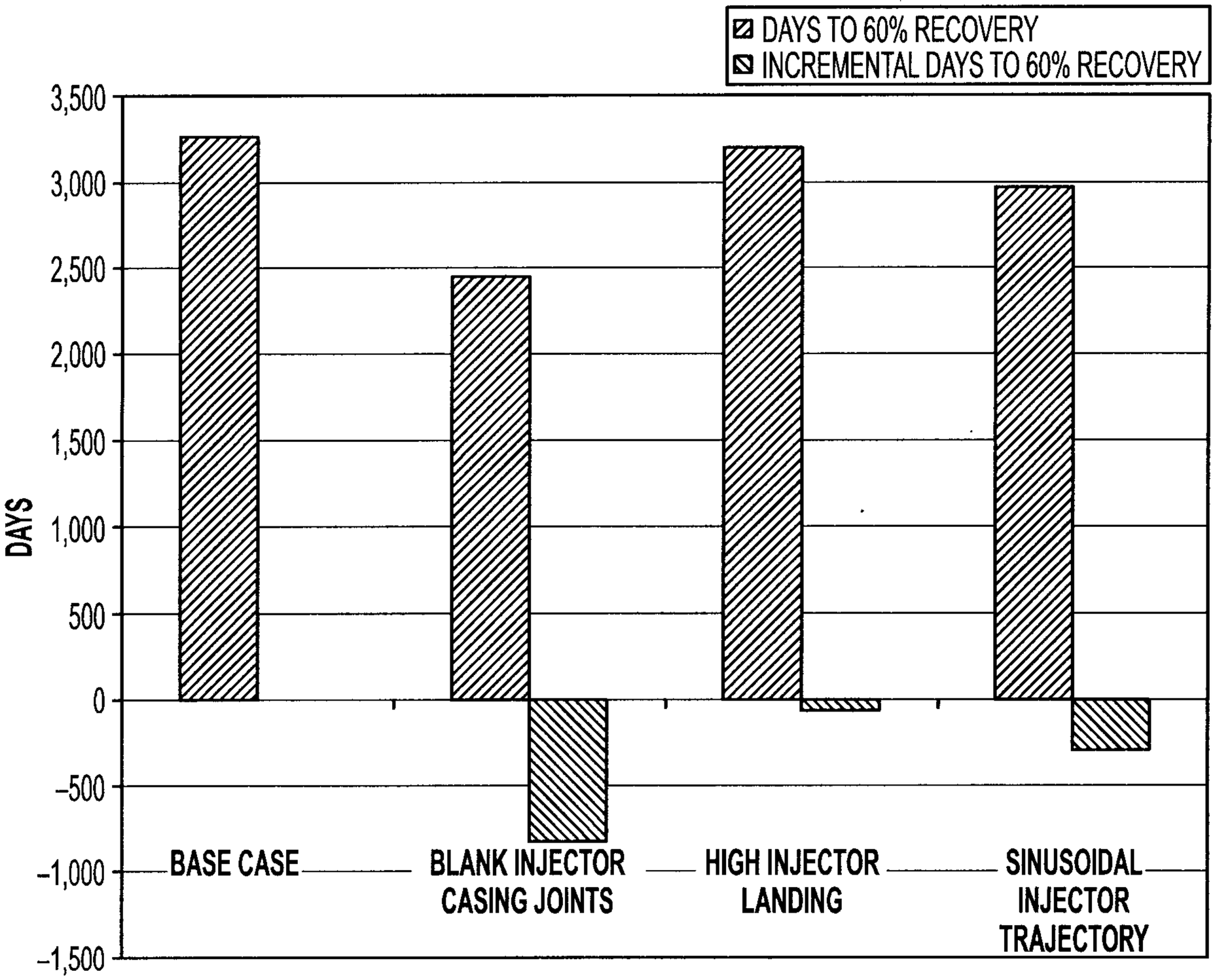

DAYS TO 60% RECOVERY
INCREMENTAL DAYS TO 60% RECOVERY
DAYS
3,500
3,000
2,500
2,000
1,500
1,000
500
0
-500
-1,000
-1,500
BASE CASE
BLANK INJECTOR CASING JOINTS
HIGH INJECTOR LANDING
SINUSOIDAL INJECTOR TRAJECTORY

FIG. 17

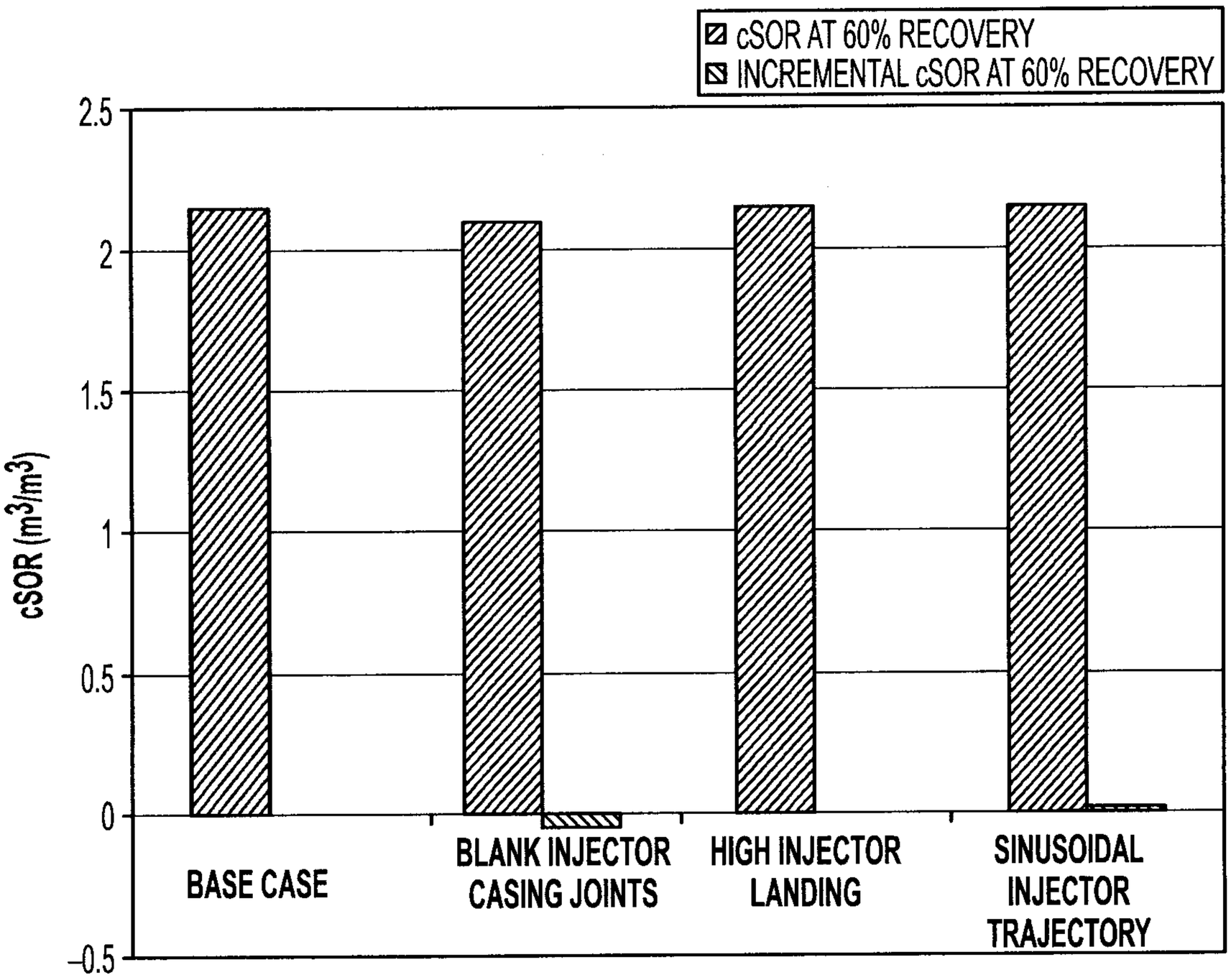

cSOR AT 60% RECOVERY
INCREMENTAL cSOR AT 60% RECOVERY
cSOR (m3/m3)
2.5
2
1.5
1
0.5
0
–0.5
BASE CASE
BLANK INJECTOR CASING JOINTS
HIGH INJECTOR LANDING
SINUSOIDAL INJECTOR TRAJECTORY

FIG. 18

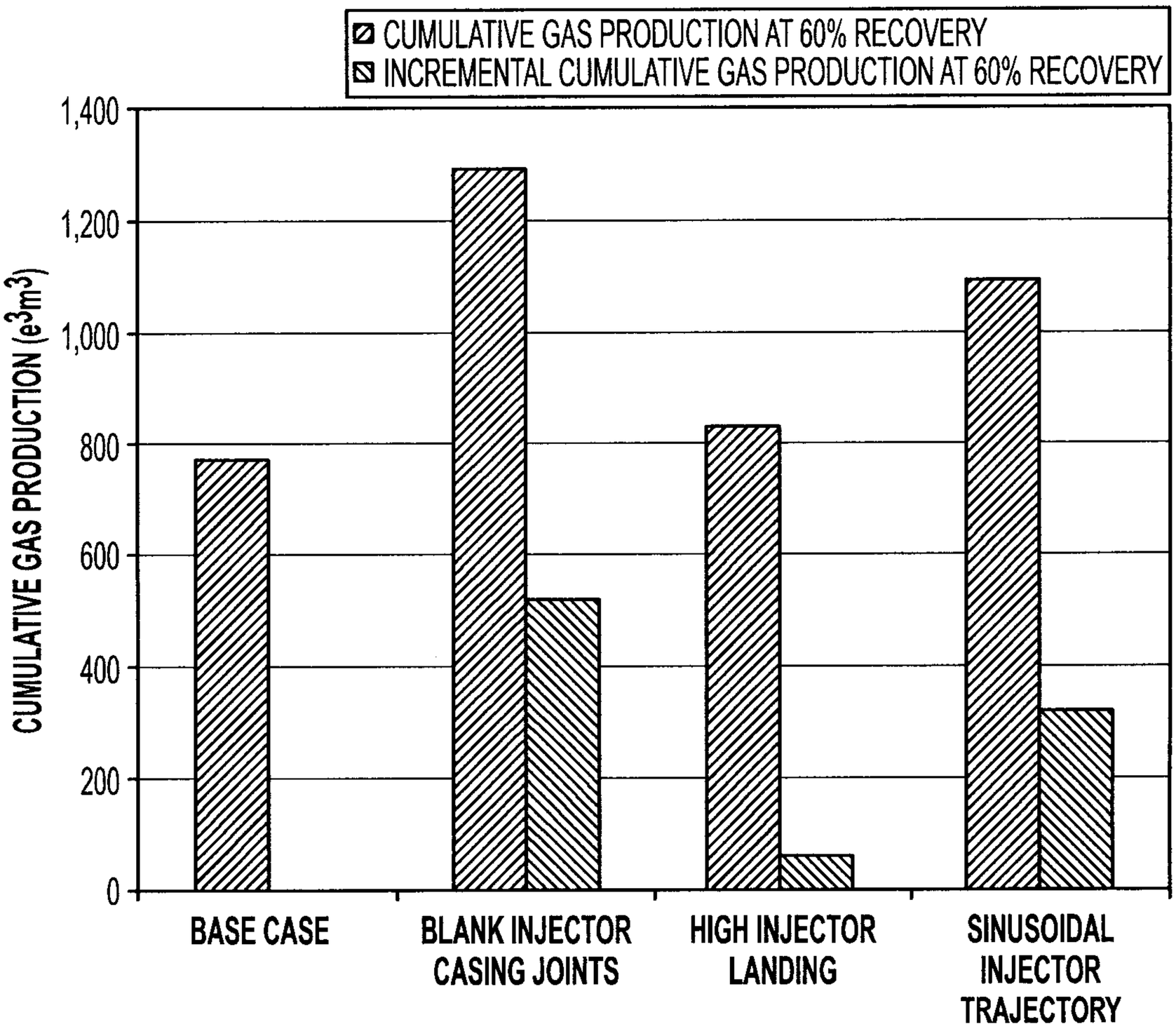

CUMULATIVE GAS PRODUCTION AT 60% RECOVERY
INCREMENTAL CUMULATIVE GAS PRODUCTION AT 60% RECOVERY
CUMULATIVE GAS PRODUCTION (e^3m^3)
1,400
1,200
1,000
800
600
400
200
0
BASE CASE
BLANK INJECTOR CASING JOINTS
HIGH INJECTOR LANDING
SINUSOIDAL INJECTOR TRAJECTORY

FIG. 19

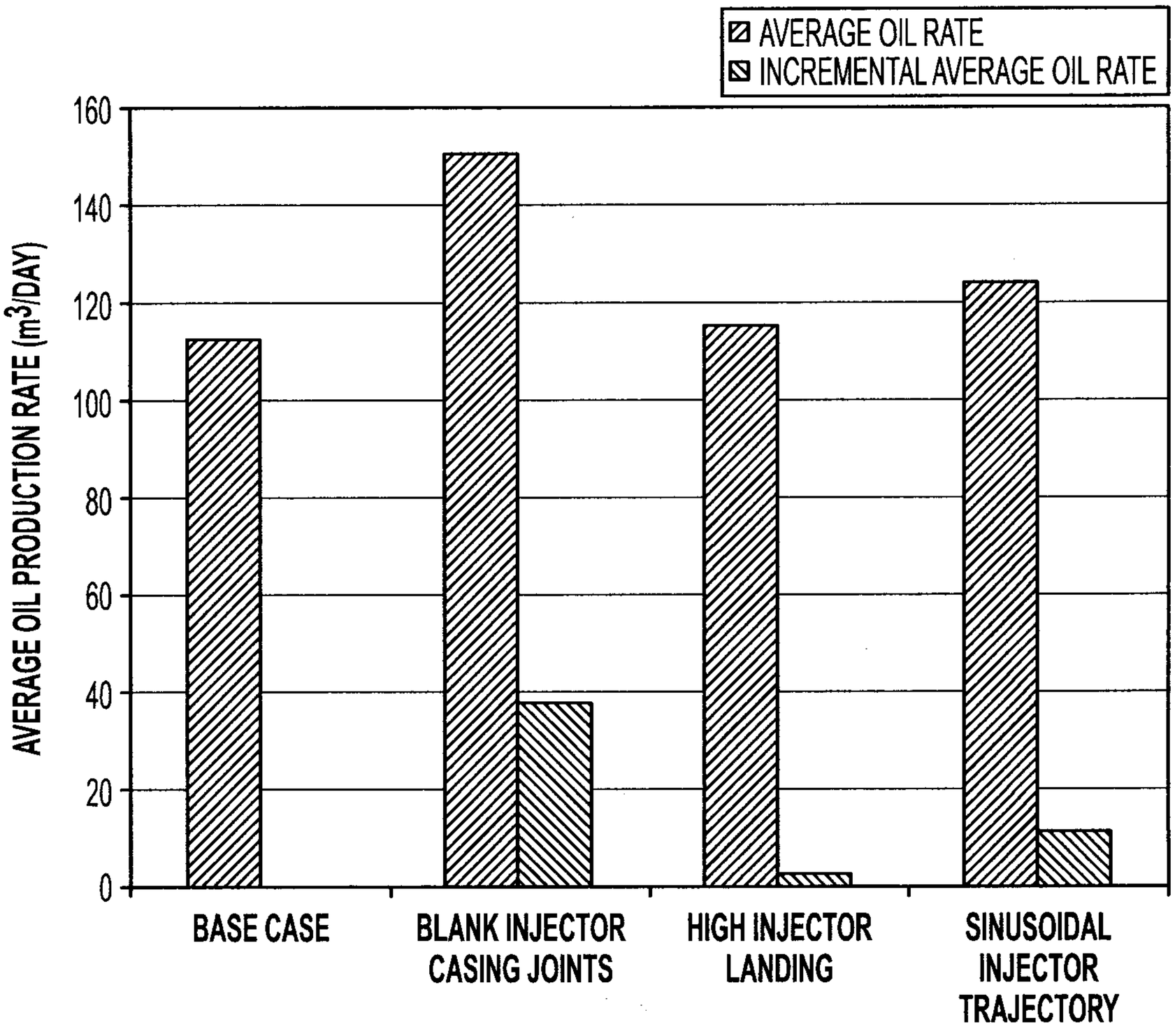

AVERAGE OIL RATE
INCREMENTAL AVERAGE OIL RATE
AVERAGE OIL PRODUCTION RATE (m3/DAY)
160
140
120
100
80
60
40
20
0
BASE CASE
BLANK INJECTOR CASING JOINTS
HIGH INJECTOR LANDING
SINUSOIDAL INJECTOR TRAJECTORY

FIG. 20

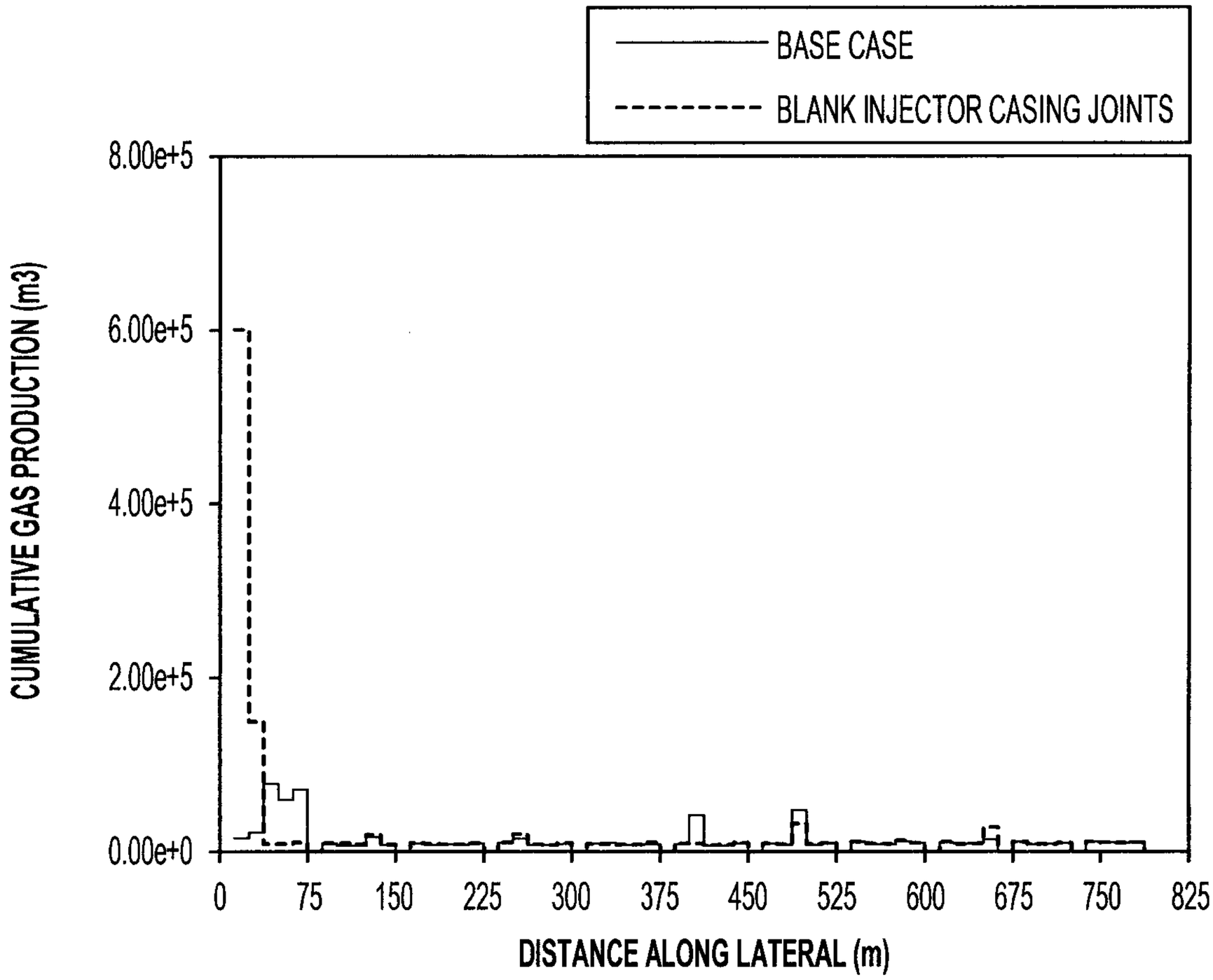

BASE CASE
BLANK INJECTOR CASING JOINTS
8.00e+5
6.00e+5
4.00e+5
2.00e+5
0.00e+0
CUMULATIVE GAS PRODUCTION (m3)
0
75
150
225
300
375
450
525
600
675
750
825
DISTANCE ALONG LATERAL (m)

FIG. 21

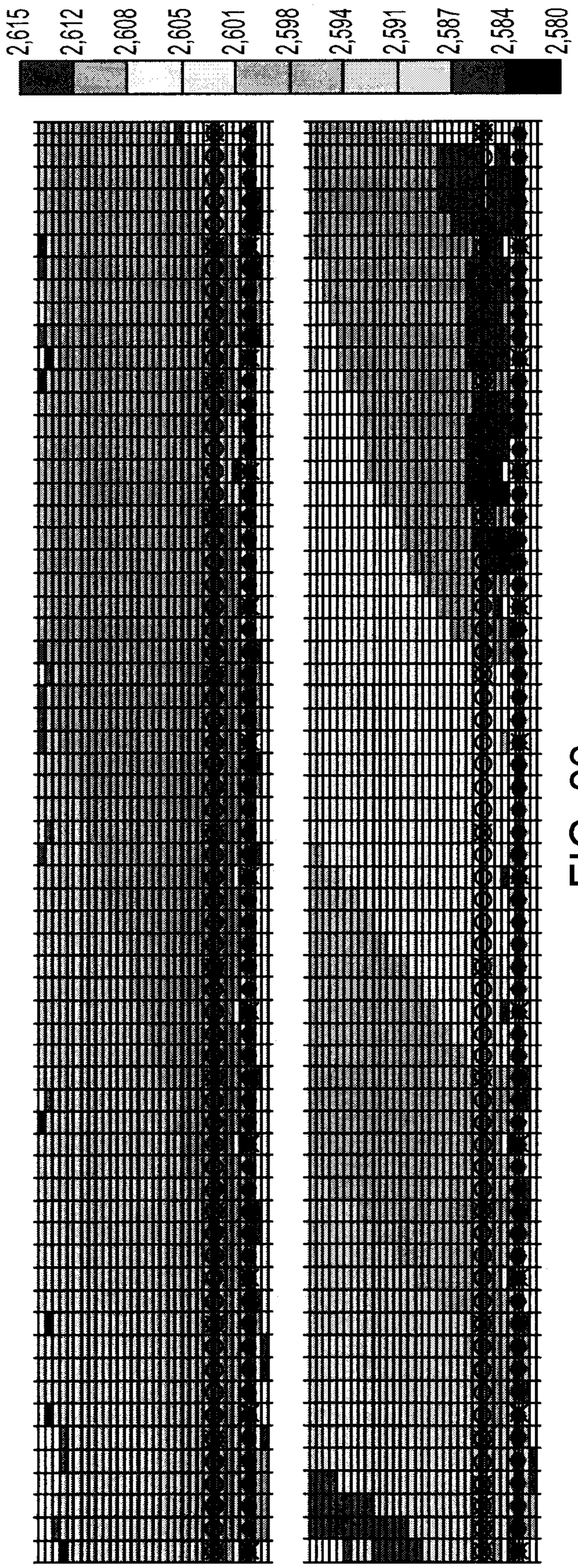


FIG. 22

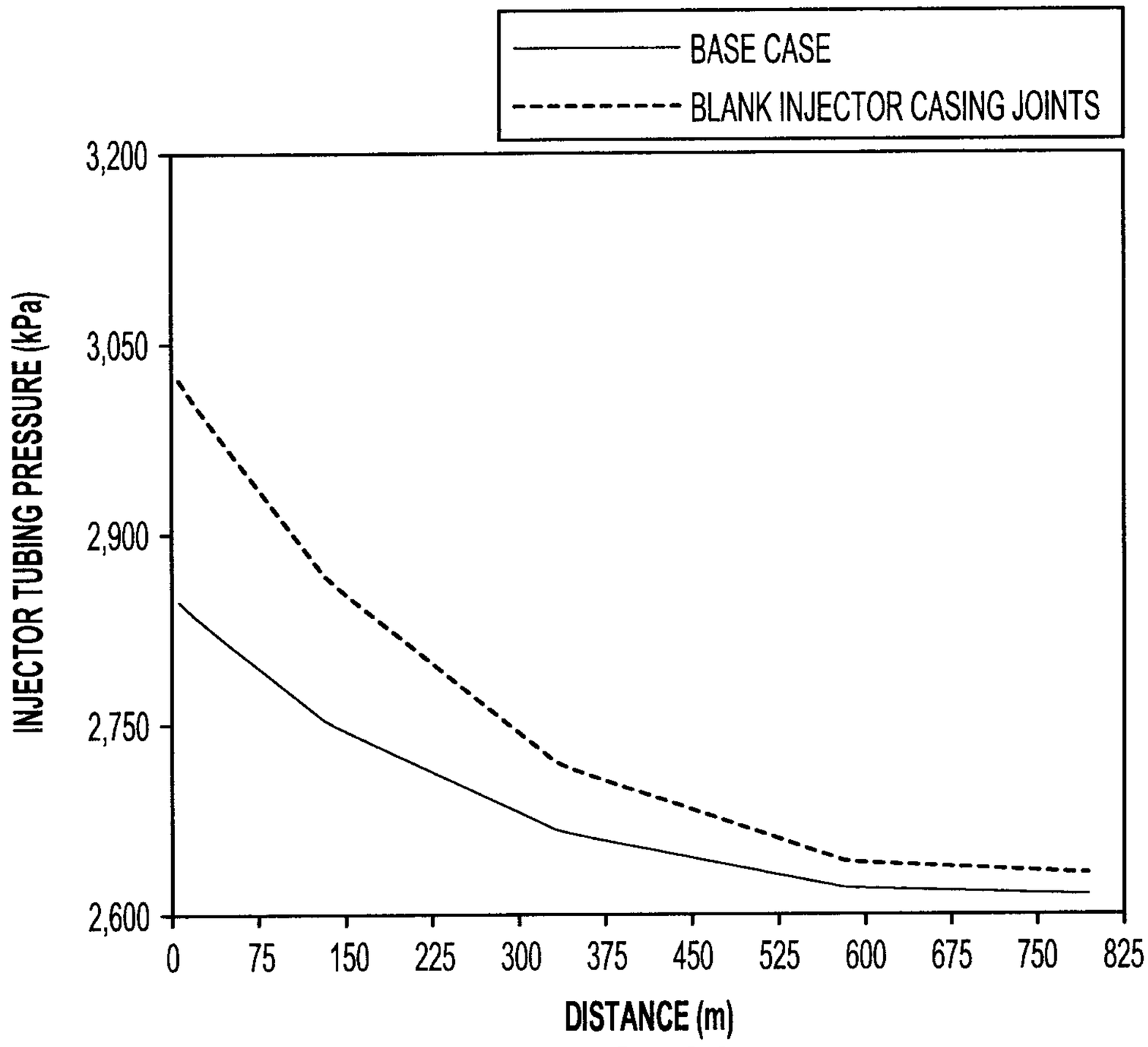

BASE CASE
BLANK INJECTOR CASING JOINTS
INJECTOR TUBING PRESSURE (kPa)
3,200
3,050
2,900
2,750
2,600
0
75
150
225
300
375
450
525
600
675
750
825
DISTANCE (m)

FIG. 23

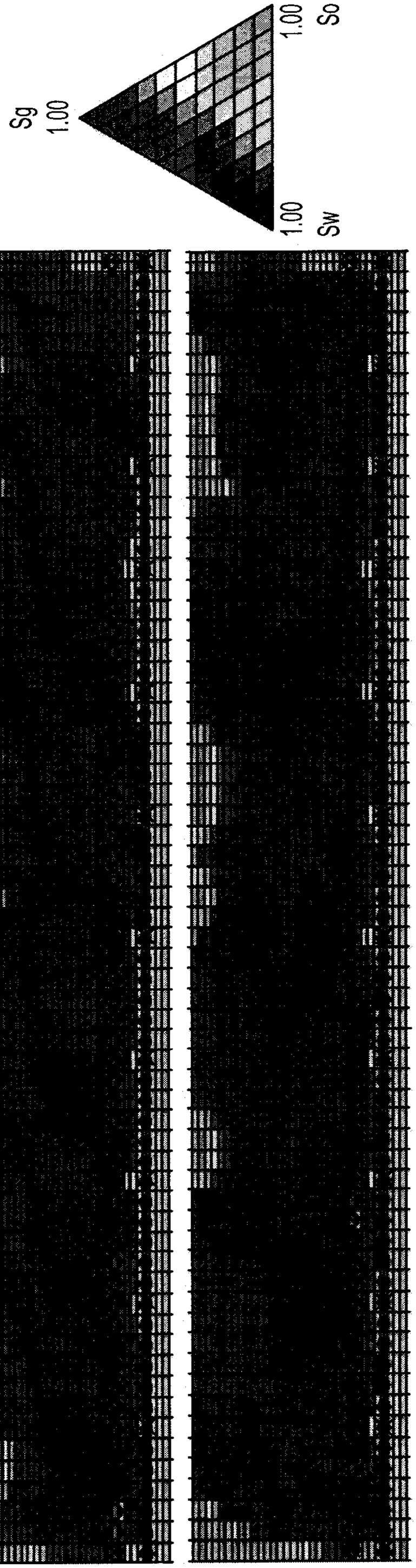


FIG. 24

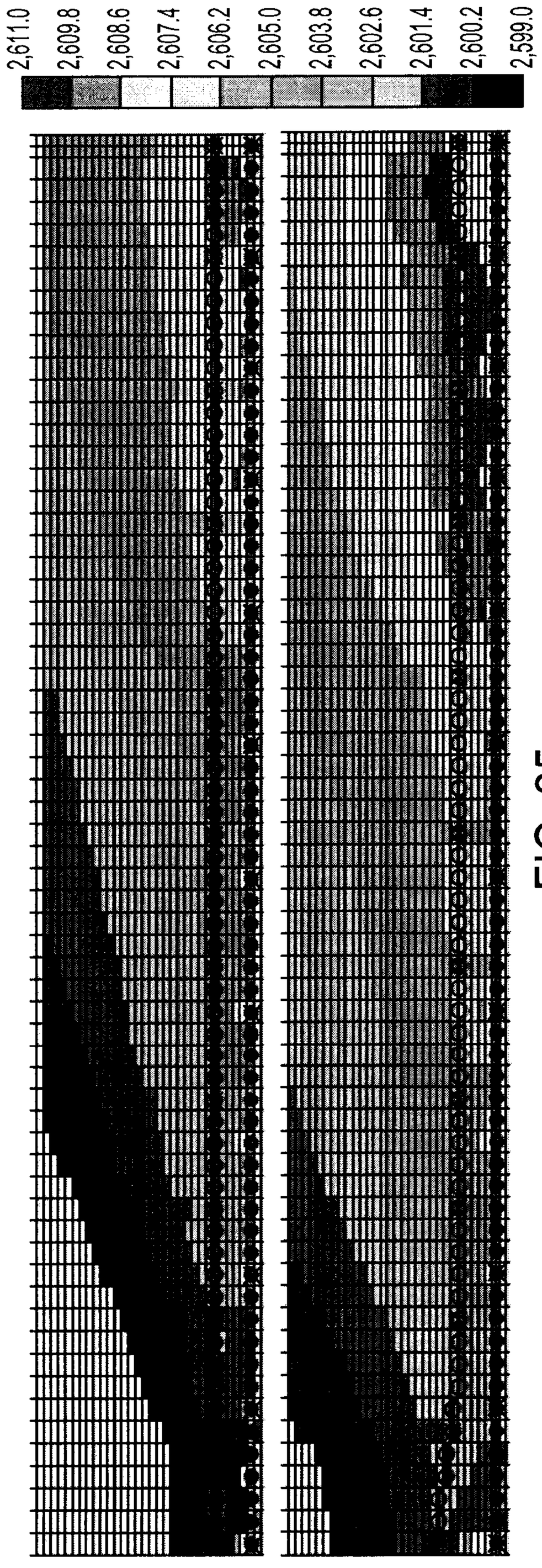

2,611.0
2,609.8
2,608.6
2,607.4
2,606.2
2,605.0
2,603.8
2,602.6
2,601.4
2,600.2
2,599.0

FIG. 25

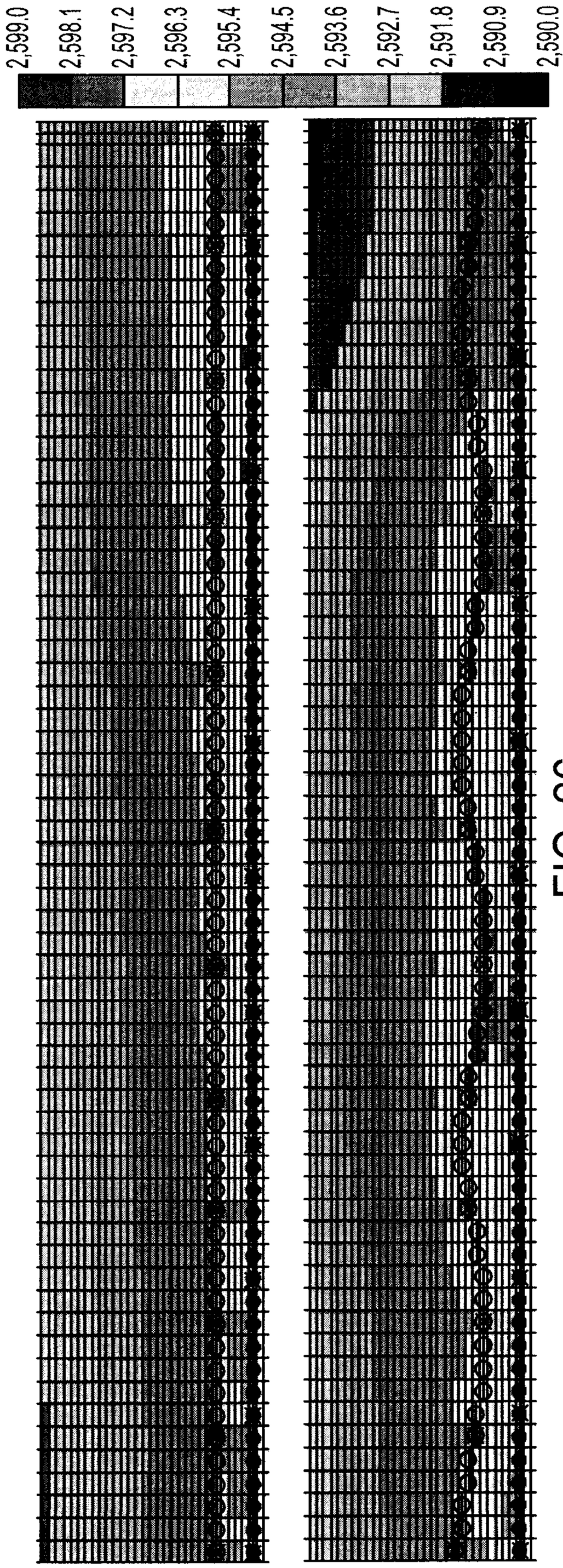

2,599.0
2,598.1
2,597.2
2,596.3
2,595.4
2,594.5
2,593.6
2,592.7
2,591.8
2,590.9
2,590.0

FIG. 26

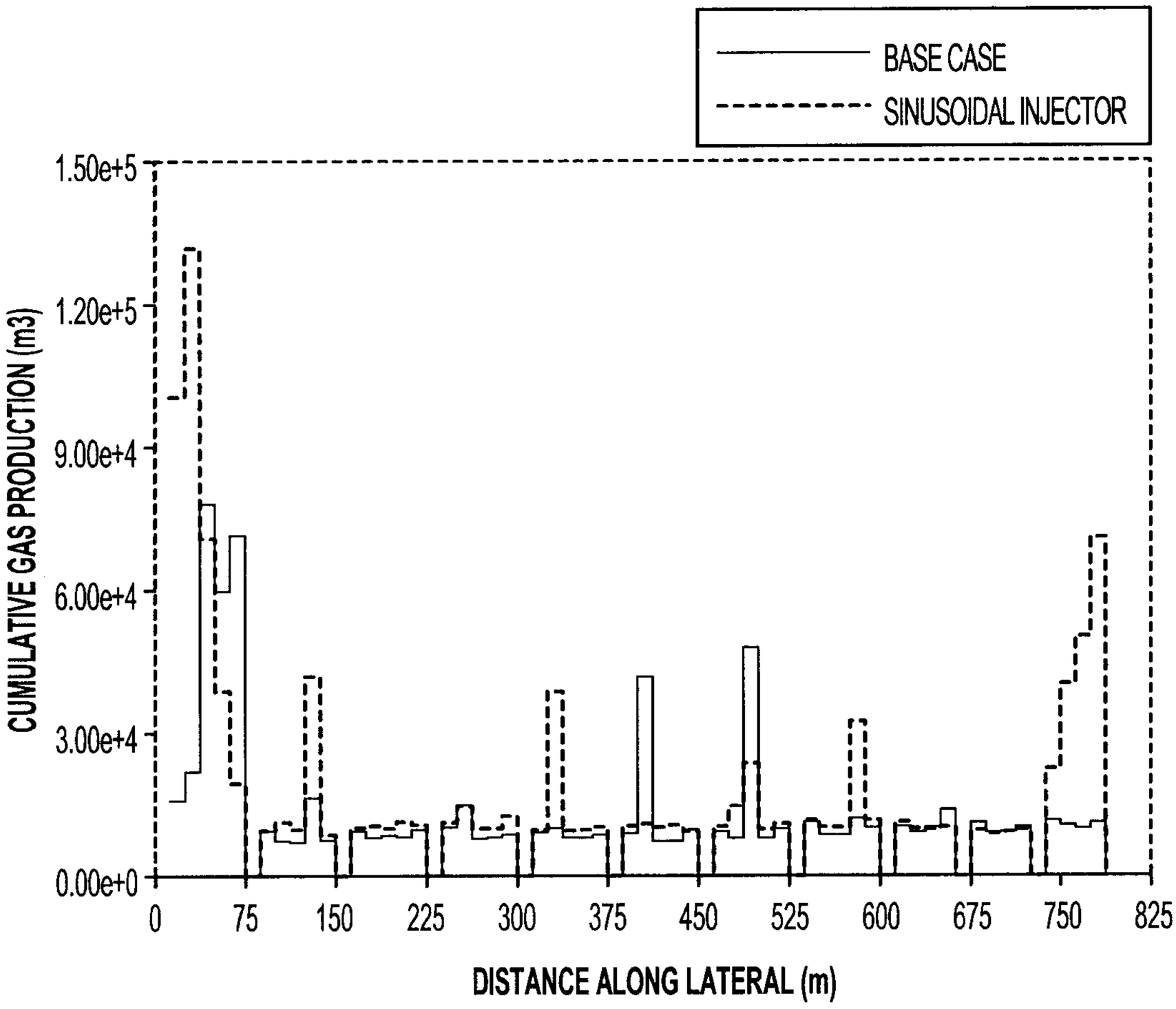

BASE CASE
SINUSOIDAL INJECTOR
CUMULATIVE GAS PRODUCTION (m3)
1.50e+5
1.20e+5
9.00e+4
6.00e+4
3.00e+4
0.00e+0
0
75
150
225
300
375
450
525
600
675
750
825
DISTANCE ALONG LATERAL (m)

FIG. 27

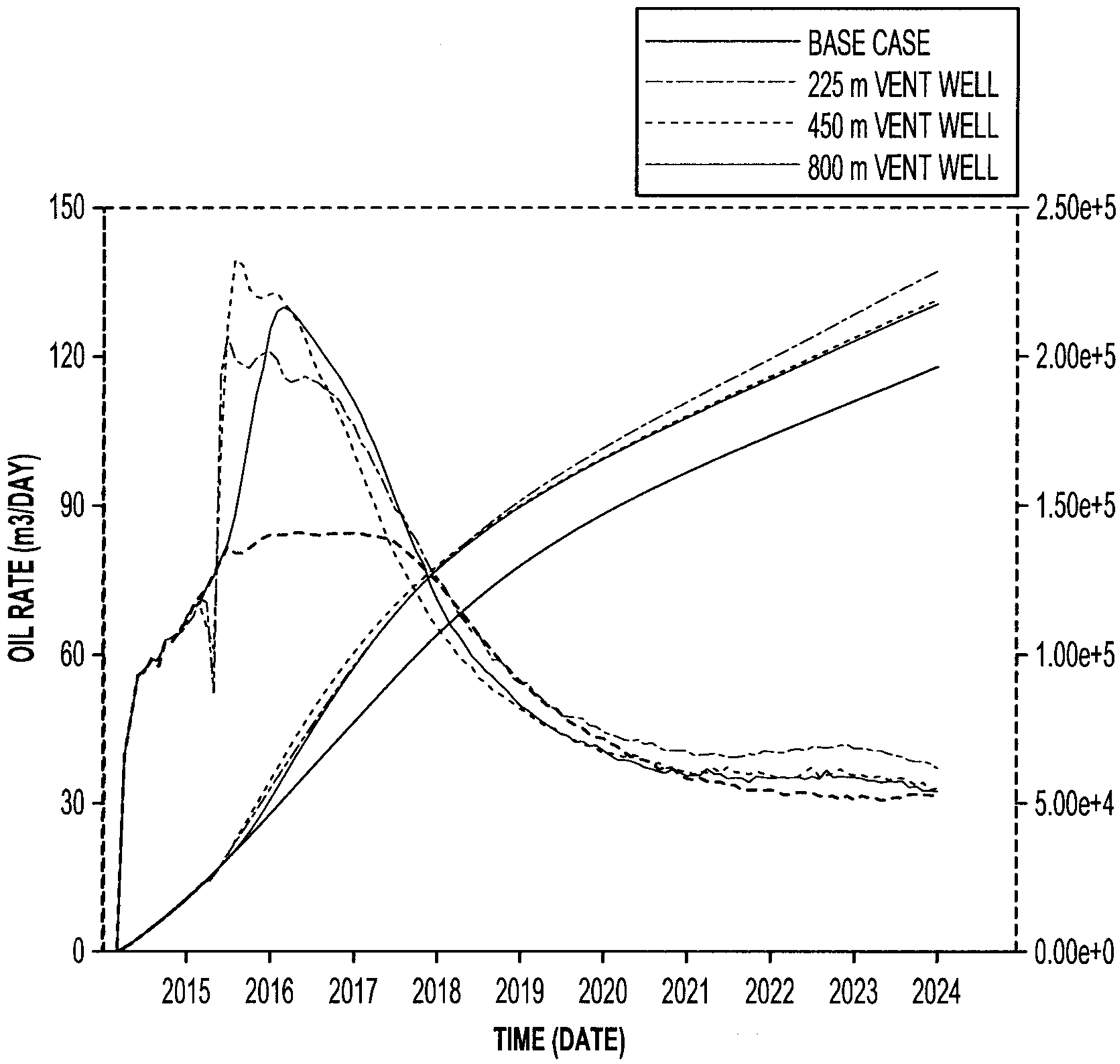

BASE CASE
225 m VENT WELL
450 m VENT WELL
800 m VENT WELL
150
120
90
60
30
0
OIL RATE (m3/DAY)
2.50e+5
2.00e+5
1.50e+5
1.00e+5
5.00e+4
0.00e+0
CUMULATIVE OIL (m3)
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
TIME (DATE)

FIG. 28

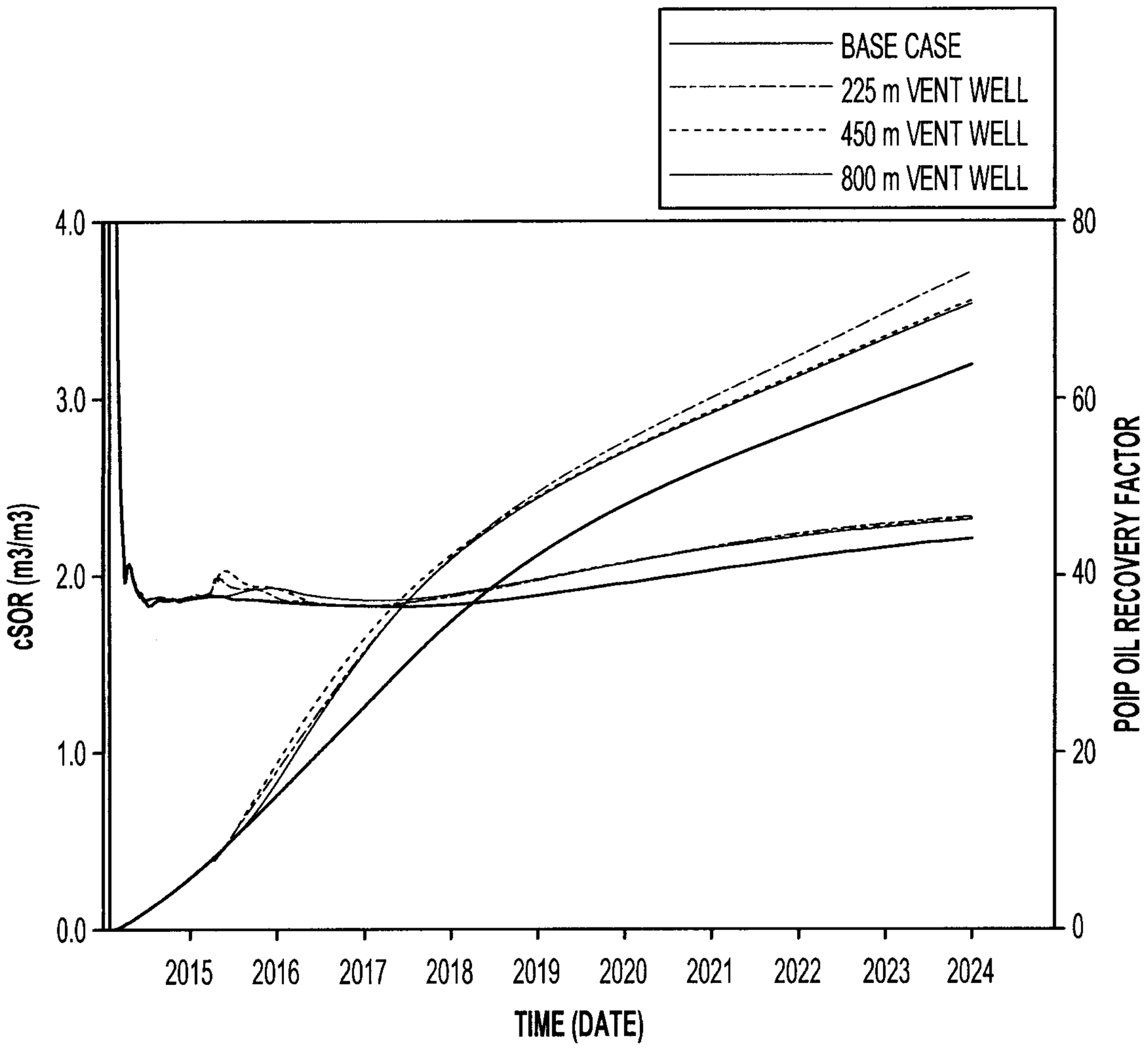

BASE CASE
225 m VENT WELL
450 m VENT WELL
800 m VENT WELL
4.0
3.0
2.0
1.0
0.0
cSOR (m3/m3)
80
60
40
20
0
POIP OIL RECOVERY FACTOR
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
TIME (DATE)

FIG. 29

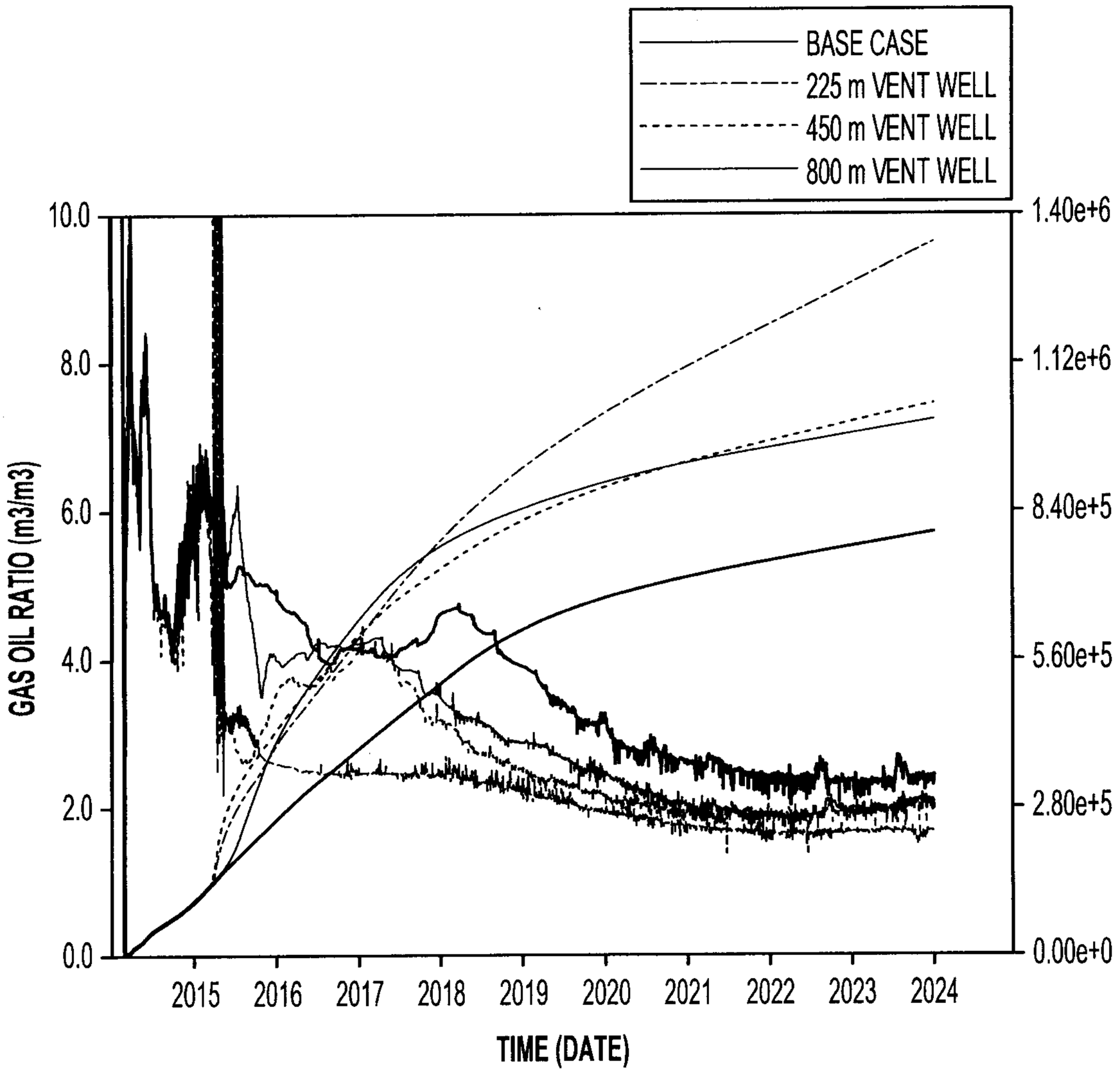

BASE CASE
225 m VENT WELL
450 m VENT WELL
800 m VENT WELL
10.0
8.0
6.0
4.0
2.0
0.0
GAS OIL RATIO (m3/m3)
1.40e+6
1.12e+6
8.40e+5
5.60e+5
2.80e+5
0.00e+0
CUMULATIVE GAS (m3)
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
TIME (DATE)

FIG. 30

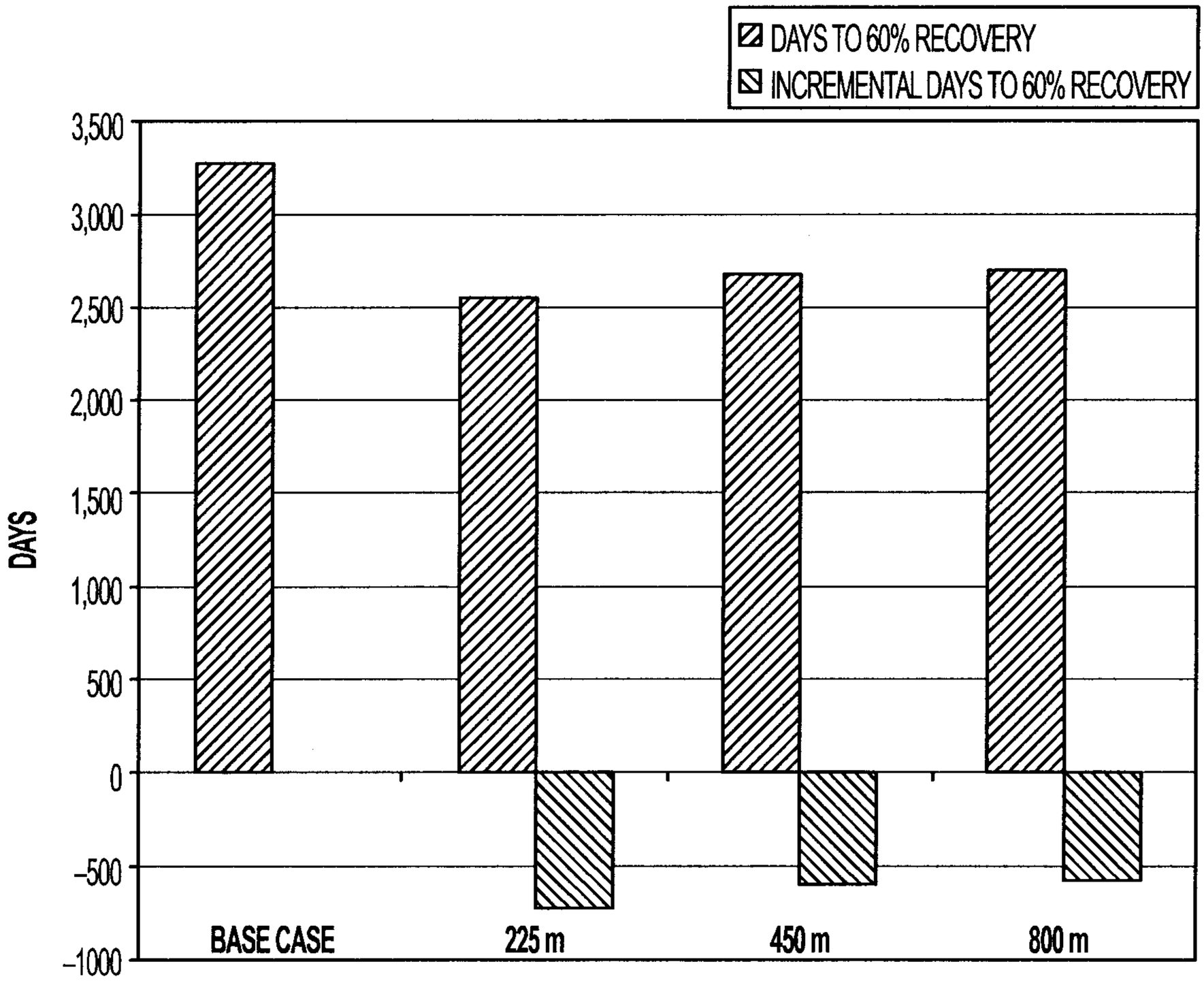

DAYS TO 60% RECOVERY
INCREMENTAL DAYS TO 60% RECOVERY
DAYS
3,500
3,000
2,500
2,000
1,500
1,000
500
0
–500
–1000
BASE CASE
225 m
450 m
800 m

FIG. 31

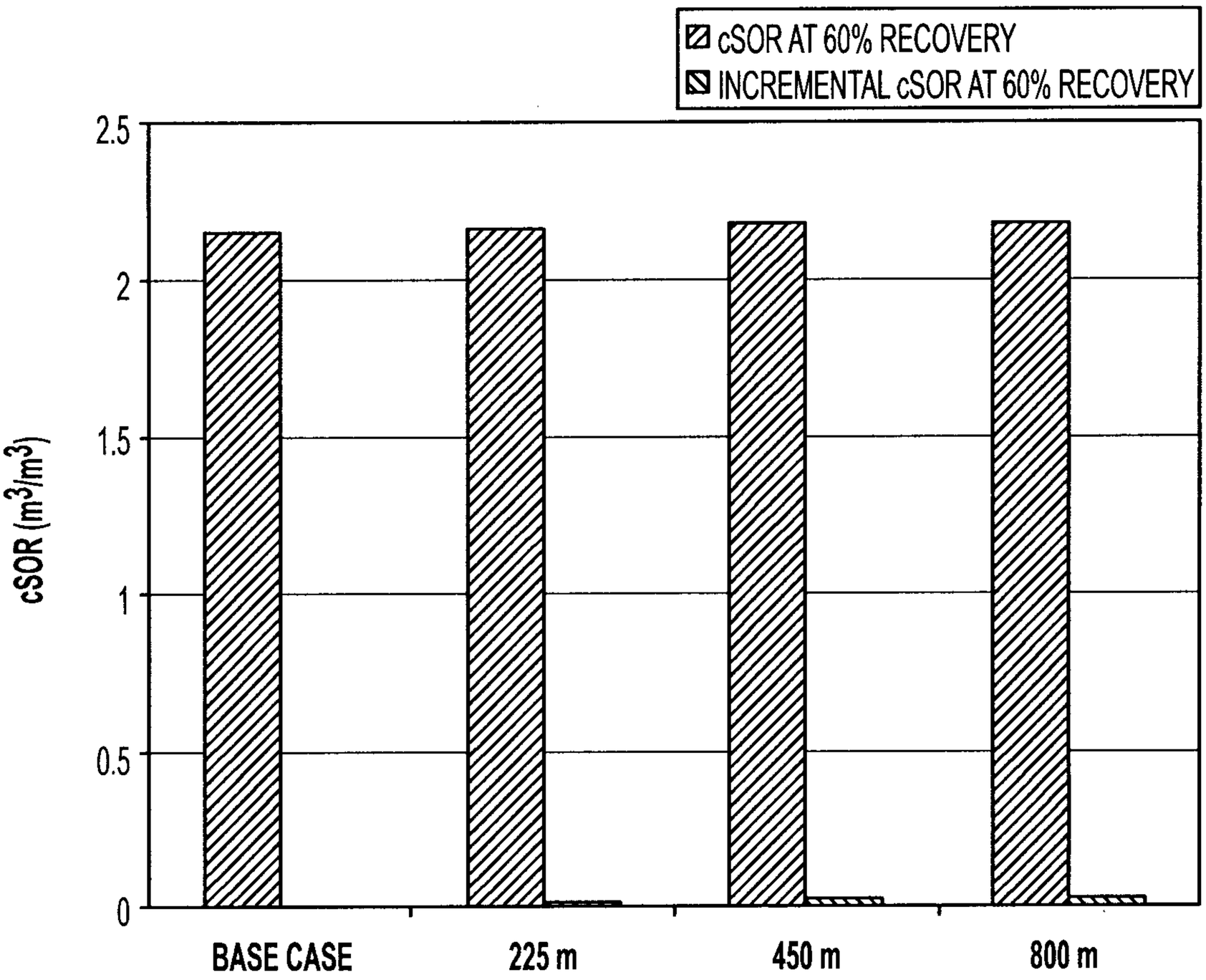

cSOR AT 60% RECOVERY
INCREMENTAL cSOR AT 60% RECOVERY
cSOR (m3/m3)
2.5
2
1.5
1
0.5
0
BASE CASE
225 m
450 m
800 m

FIG. 32

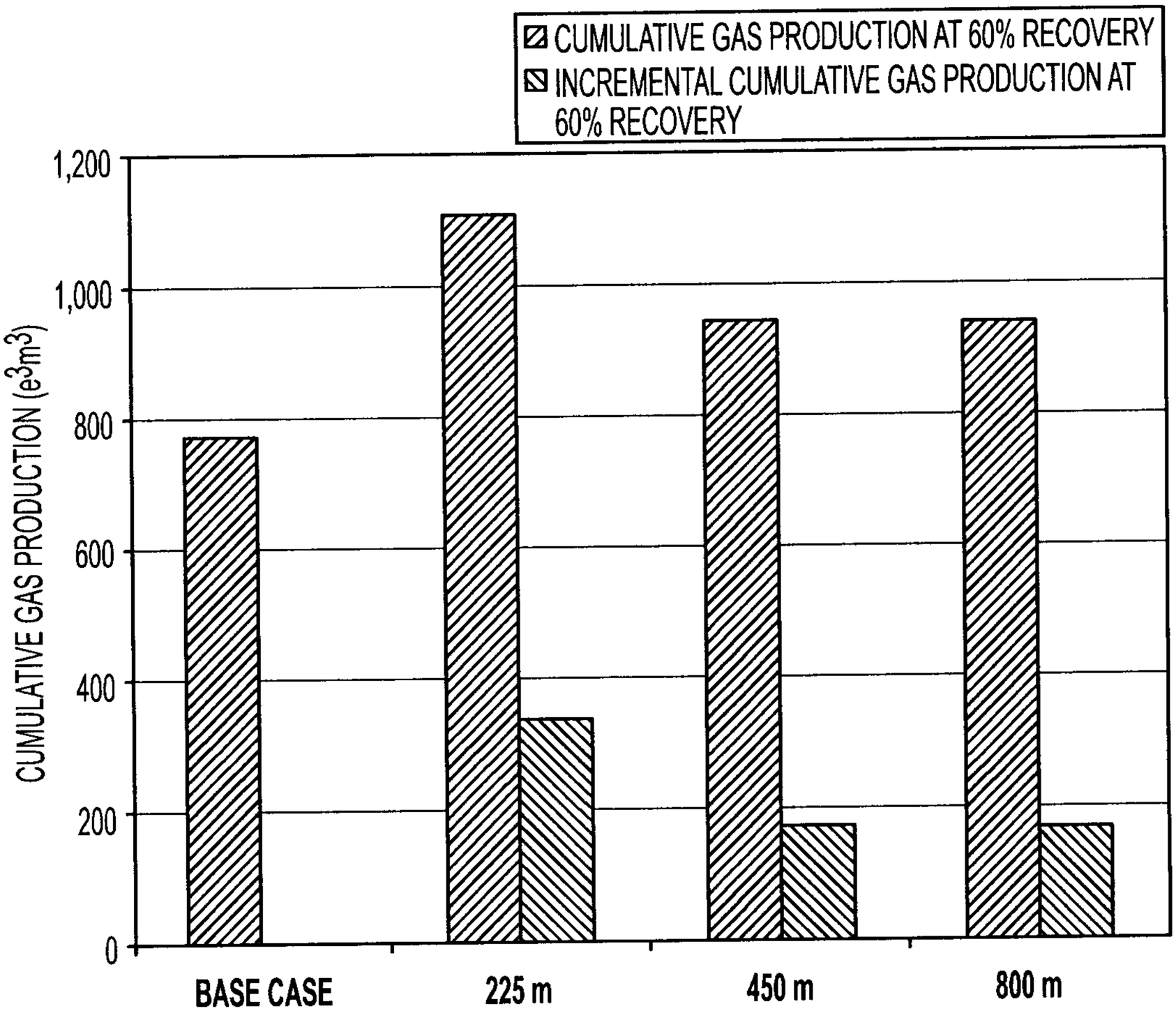

CUMULATIVE GAS PRODUCTION AT 60% RECOVERY
INCREMENTAL CUMULATIVE GAS PRODUCTION AT 60% RECOVERY
CUMULATIVE GAS PRODUCTION (e^3m^3)
1,200
1,000
800
600
400
200
0
BASE CASE
225 m
450 m
800 m

FIG. 33

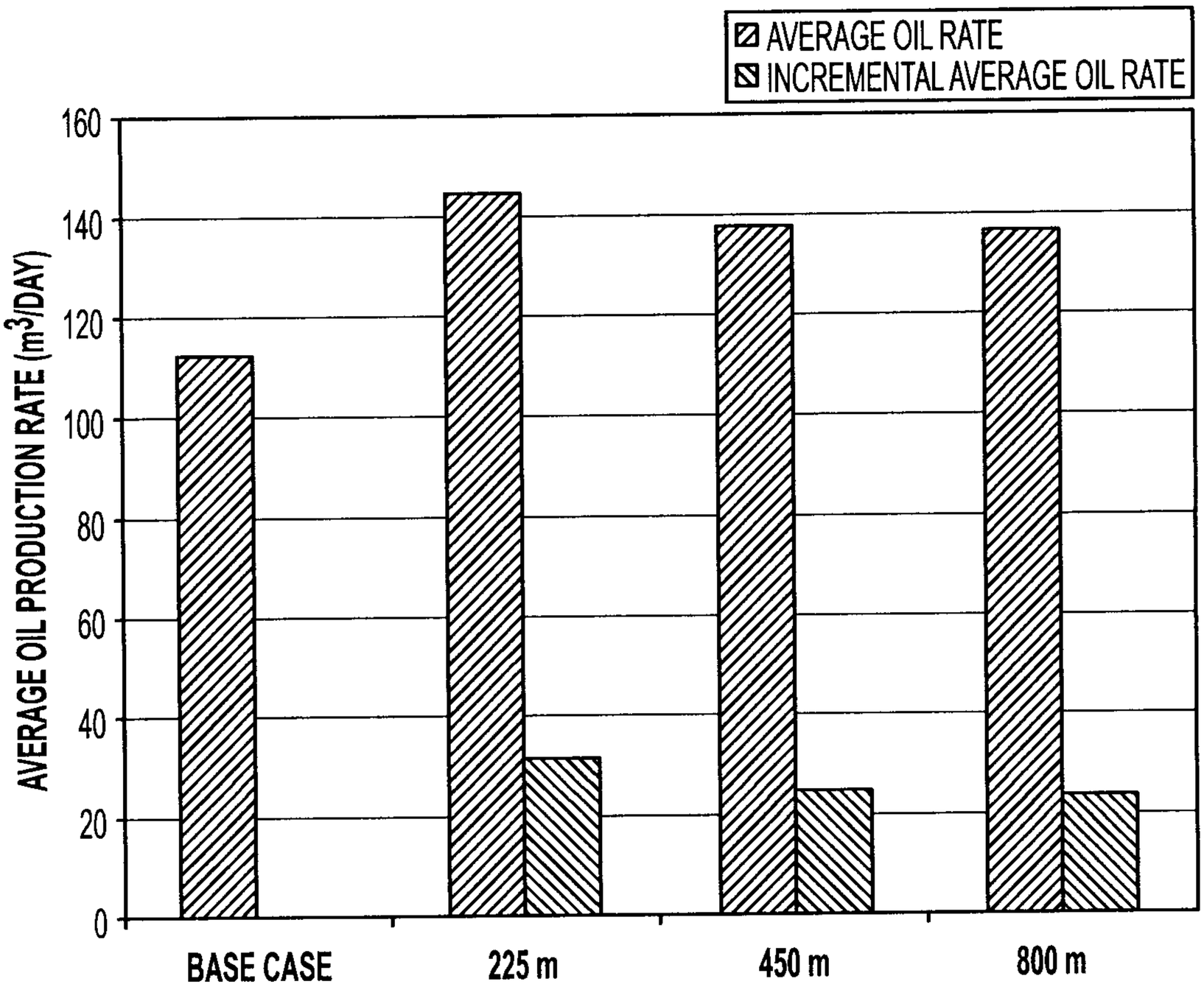

AVERAGE OIL RATE
INCREMENTAL AVERAGE OIL RATE
AVERAGE OIL PRODUCTION RATE (m3/DAY)
160
140
120
100
80
60
40
20
0
BASE CASE
225 m
450 m
800 m

FIG. 34

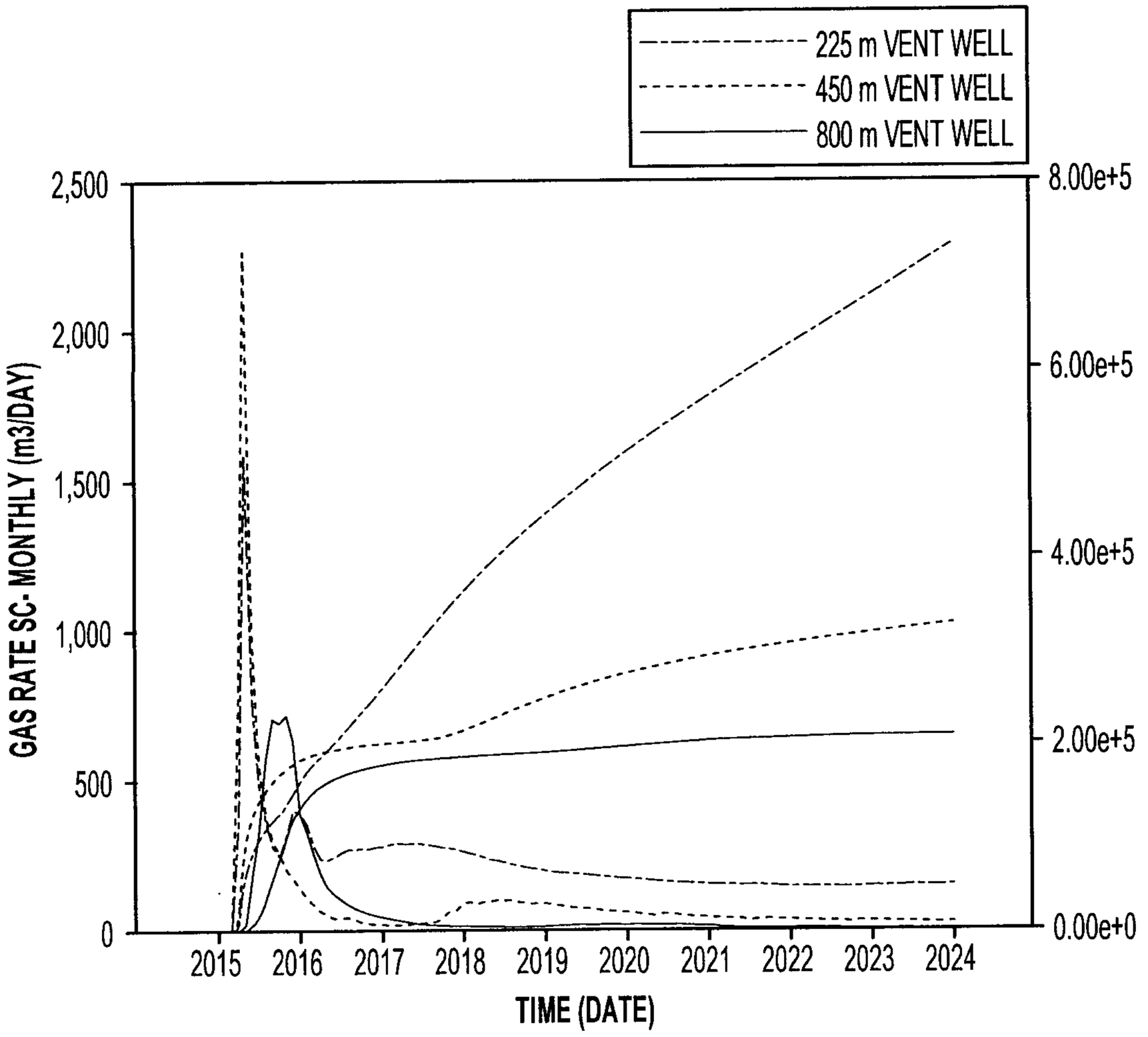

225 m VENT WELL
450 m VENT WELL
800 m VENT WELL
GAS RATE SC- MONTHLY (m3/DAY)
CUMULATIVE GAS SC (m3)
2,500
2,000
1,500
1,000
500
0
8.00e+5
6.00e+5
4.00e+5
2.00e+5
0.00e+0
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
TIME (DATE)

FIG. 35

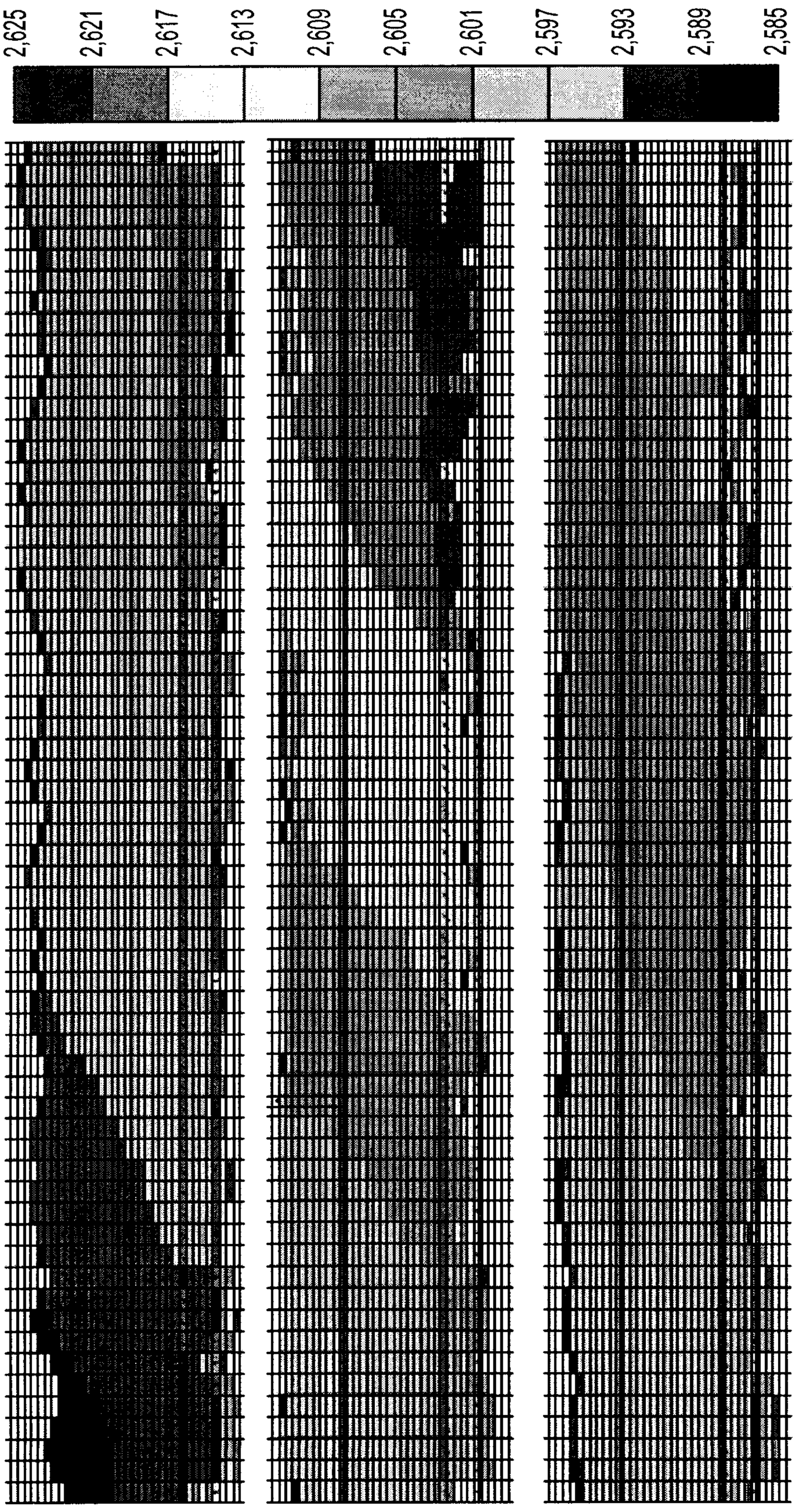


FIG. 36

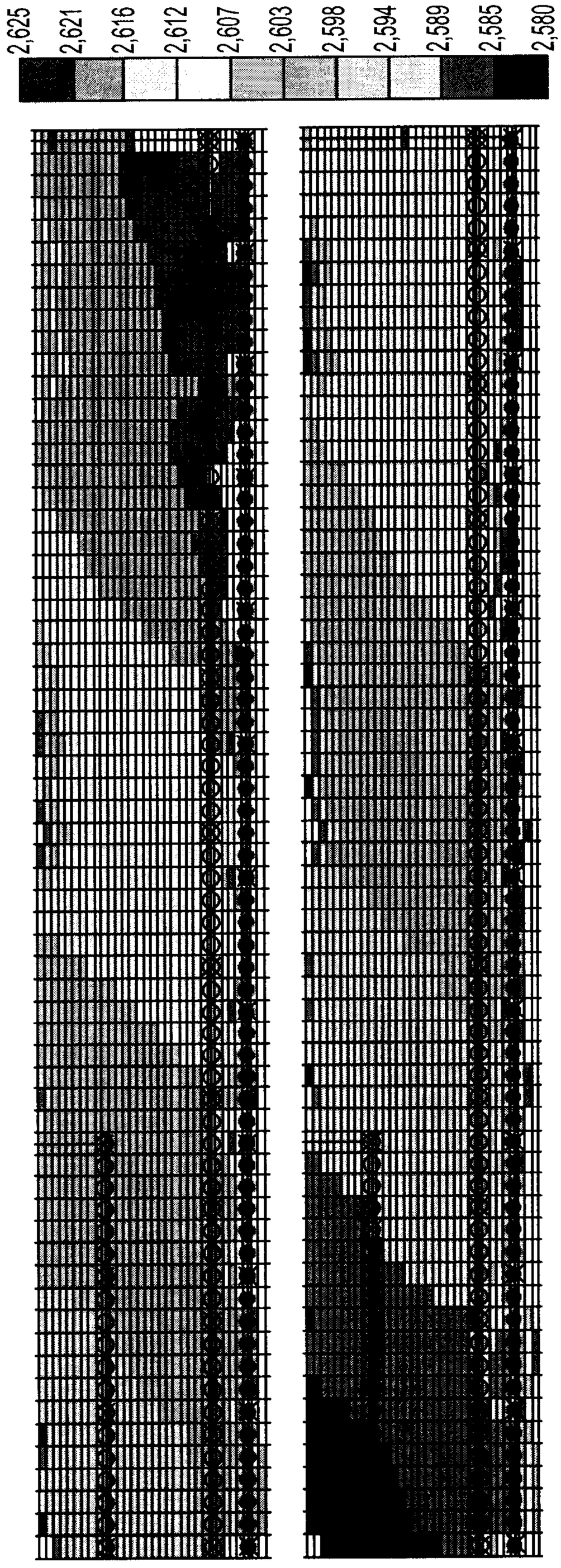


FIG. 37

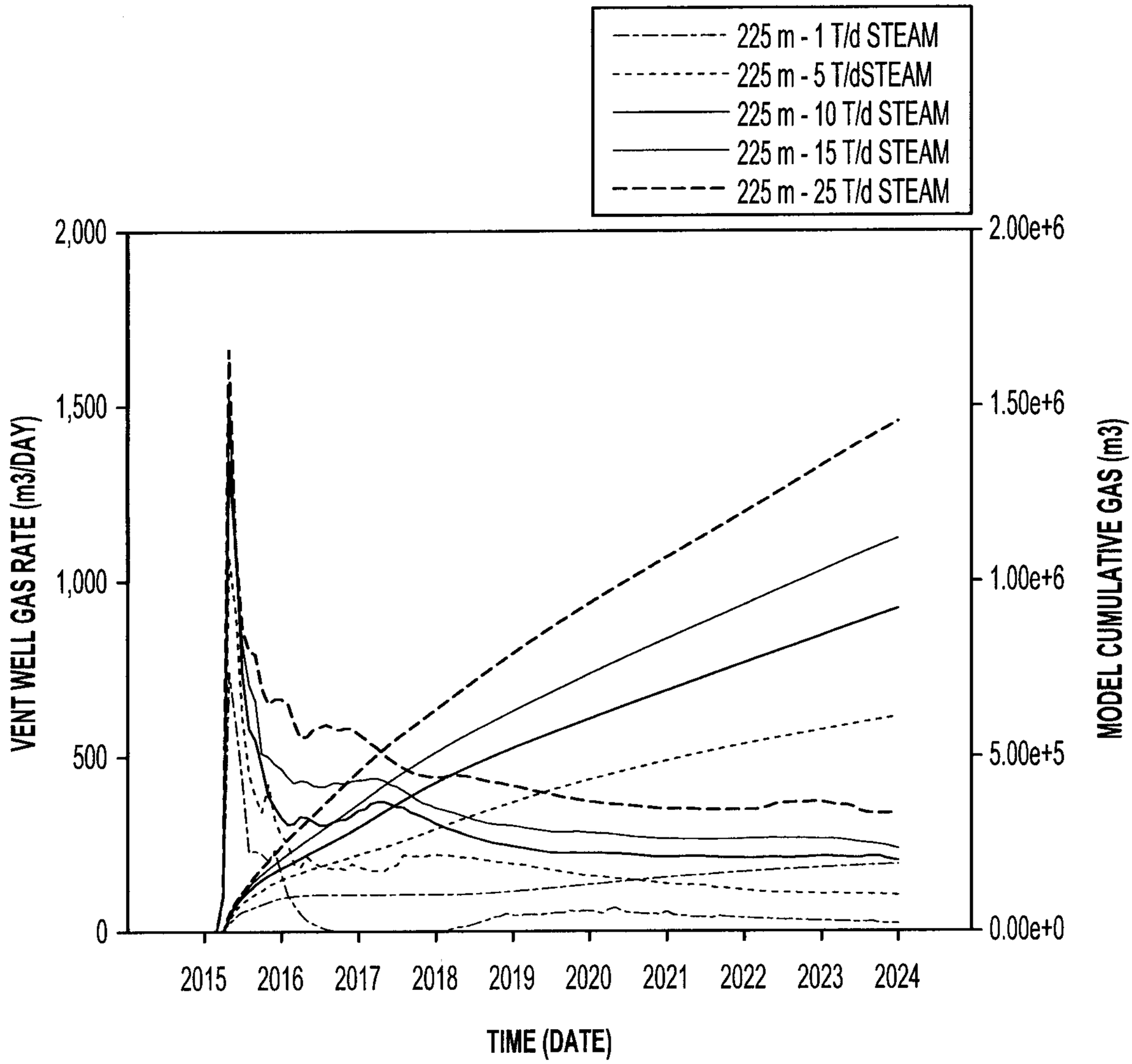

225 m - 1 T/d STEAM
225 m - 5 T/dSTEAM
225 m - 10 T/d STEAM
225 m - 15 T/d STEAM
225 m - 25 T/d STEAM
2,000
1,500
1,000
500
0
2.00e+6
1.50e+6
1.00e+6
5.00e+5
0.00e+0
VENT WELL GAS RATE (m3/DAY)
MODEL CUMULATIVE GAS (m3)
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
TIME (DATE)

FIG. 38

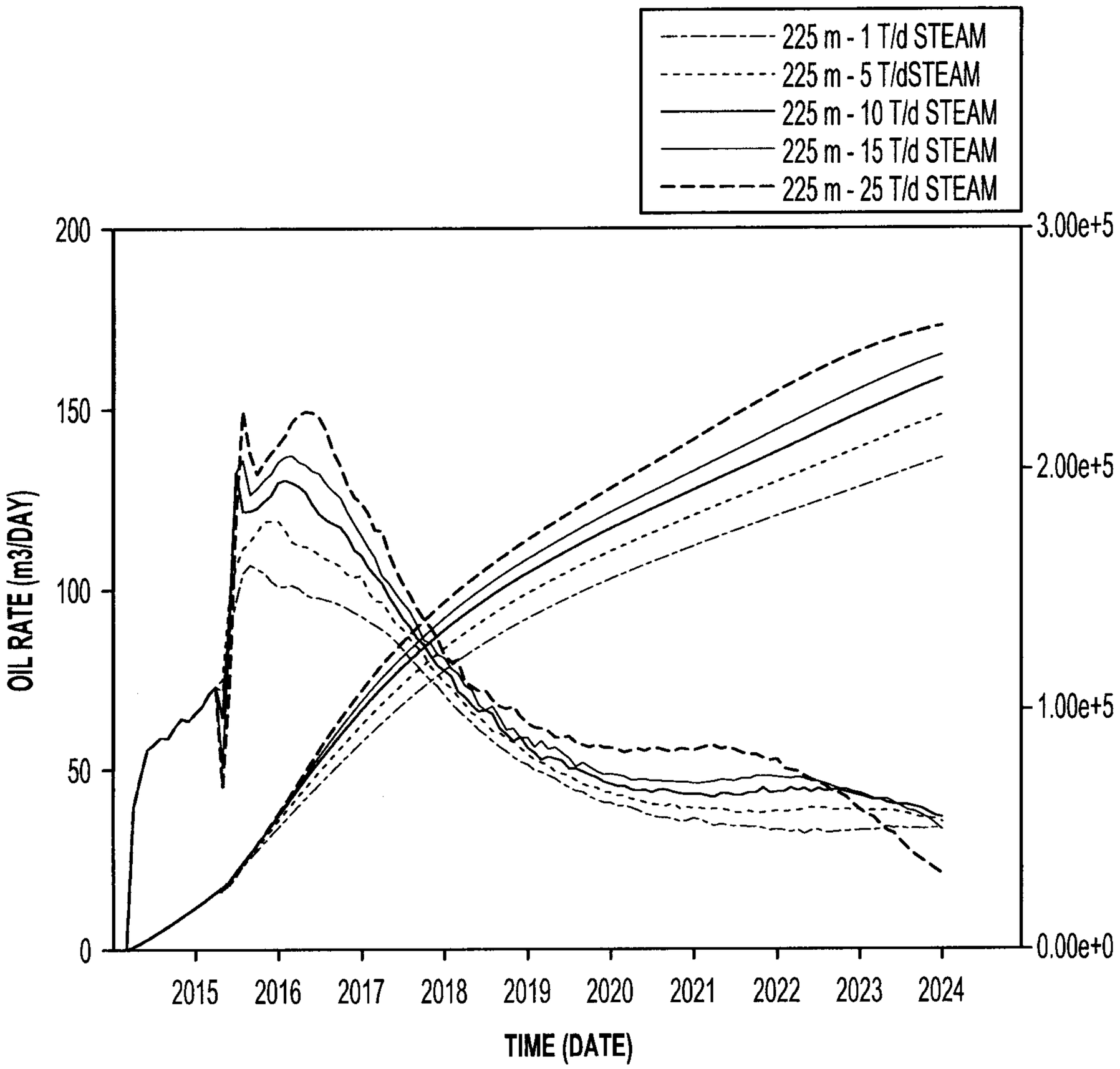

225 m - 1 T/d STEAM
225 m - 5 T/dSTEAM
225 m - 10 T/d STEAM
225 m - 15 T/d STEAM
225 m - 25 T/d STEAM
OIL RATE (m3/DAY)
CUMULATIVE OIL (m3)
200
150
100
50
0
3.00e+5
2.00e+5
1.00e+5
0.00e+0
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
TIME (DATE)

FIG. 39

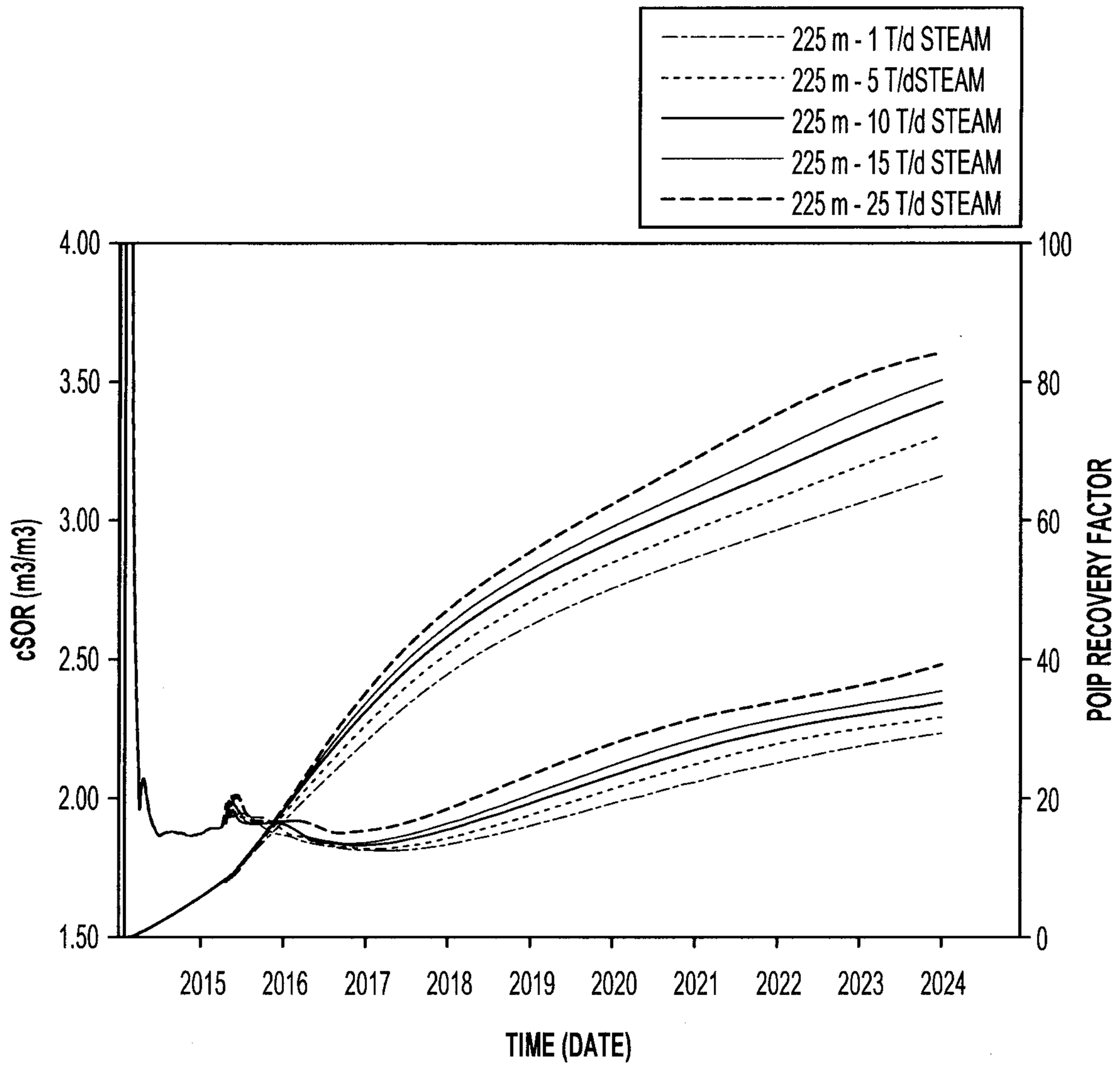

225 m - 1 T/d STEAM
225 m - 5 T/dSTEAM
225 m - 10 T/d STEAM
225 m - 15 T/d STEAM
225 m - 25 T/d STEAM
4.00
3.50
3.00
2.50
2.00
1.50
cSOR (m3/m3)
100
80
60
40
20
0
POIP RECOVERY FACTOR
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
TIME (DATE)

FIG. 40

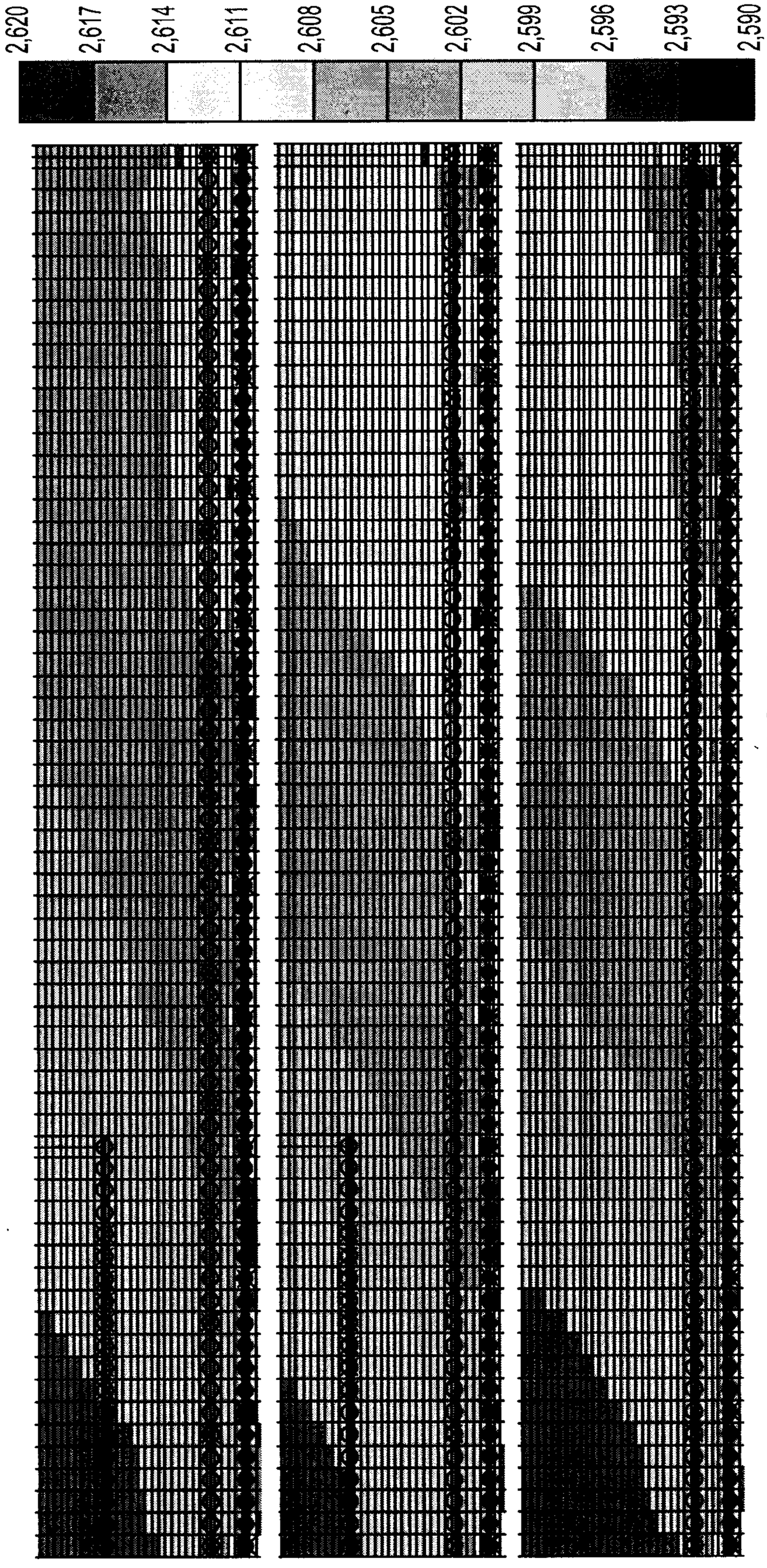


FIG. 41

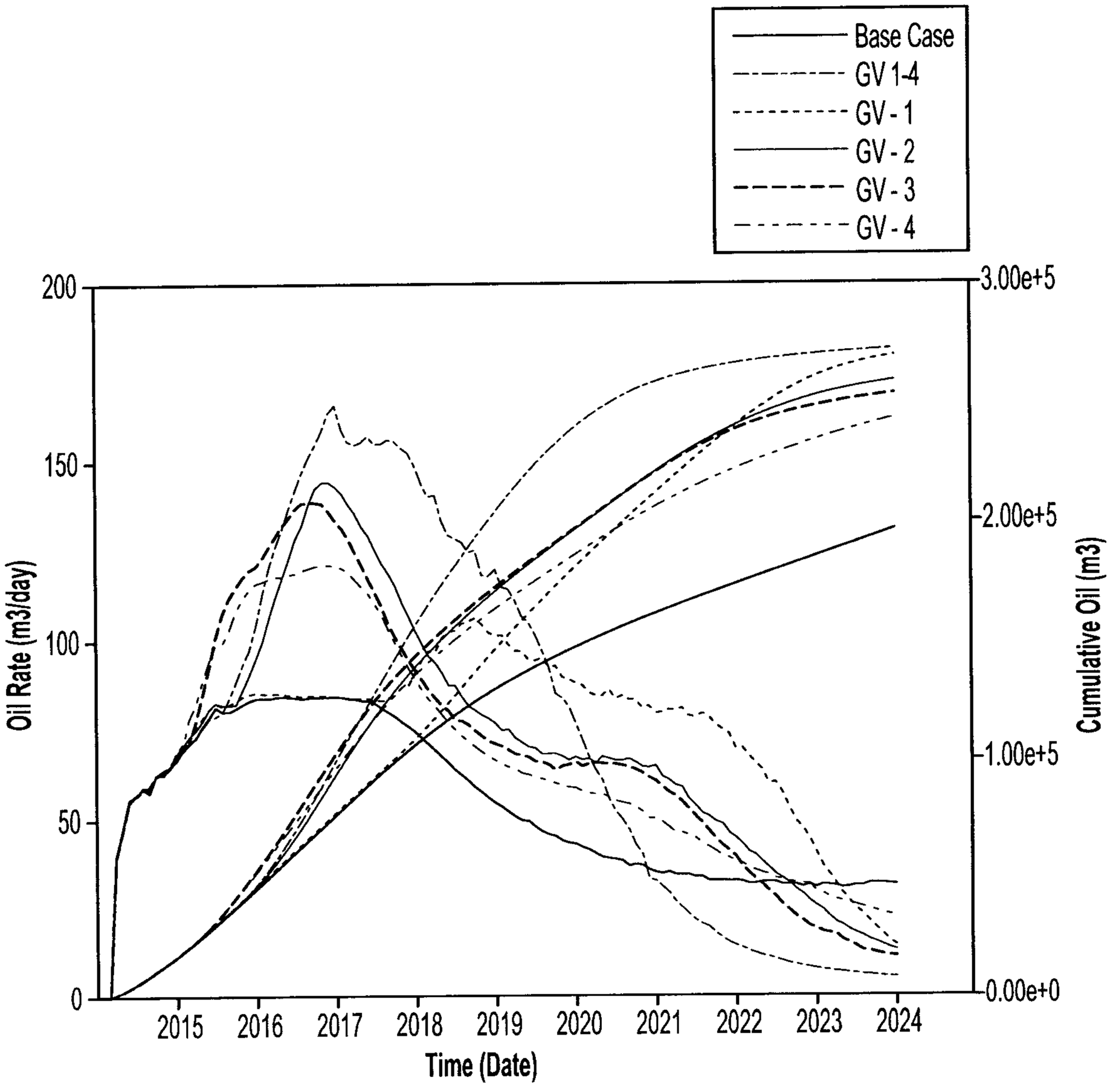

Base Case
GV 1-4
GV - 1
GV - 2
GV - 3
GV - 4
200
150
100
50
0
Oil Rate (m3/day)
3.00e+5
2.00e+5
1.00e+5
0.00e+0
Cumulative Oil (m3)
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Time (Date)

FIG. 42

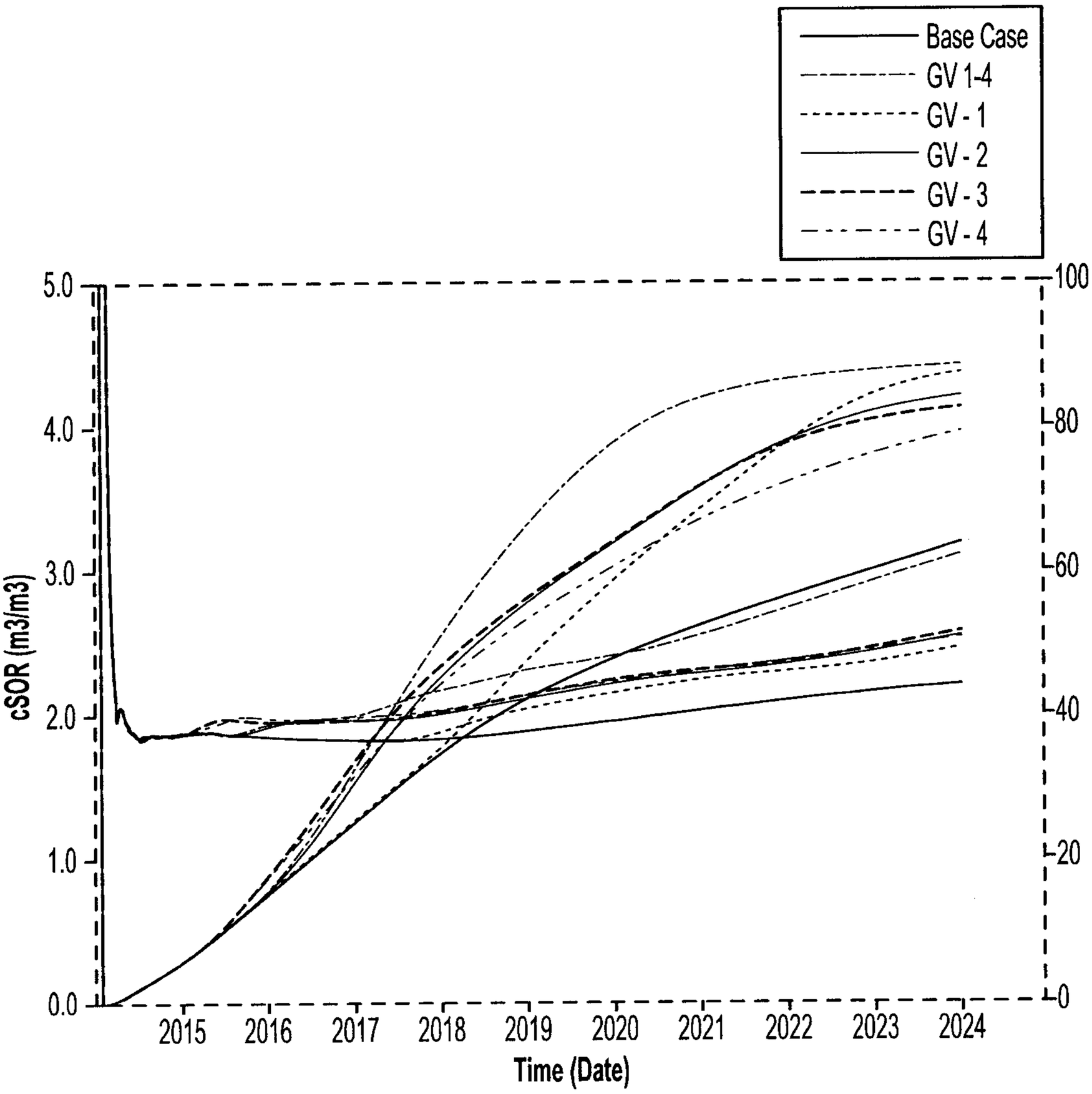

Base Case
GV 1-4
GV - 1
GV - 2
GV - 3
GV - 4
5.0
4.0
3.0
2.0
1.0
0.0
cSOR (m3/m3)
100
80
60
40
20
0
POIP Oil Recovery Factor
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Time (Date)

FIG. 43

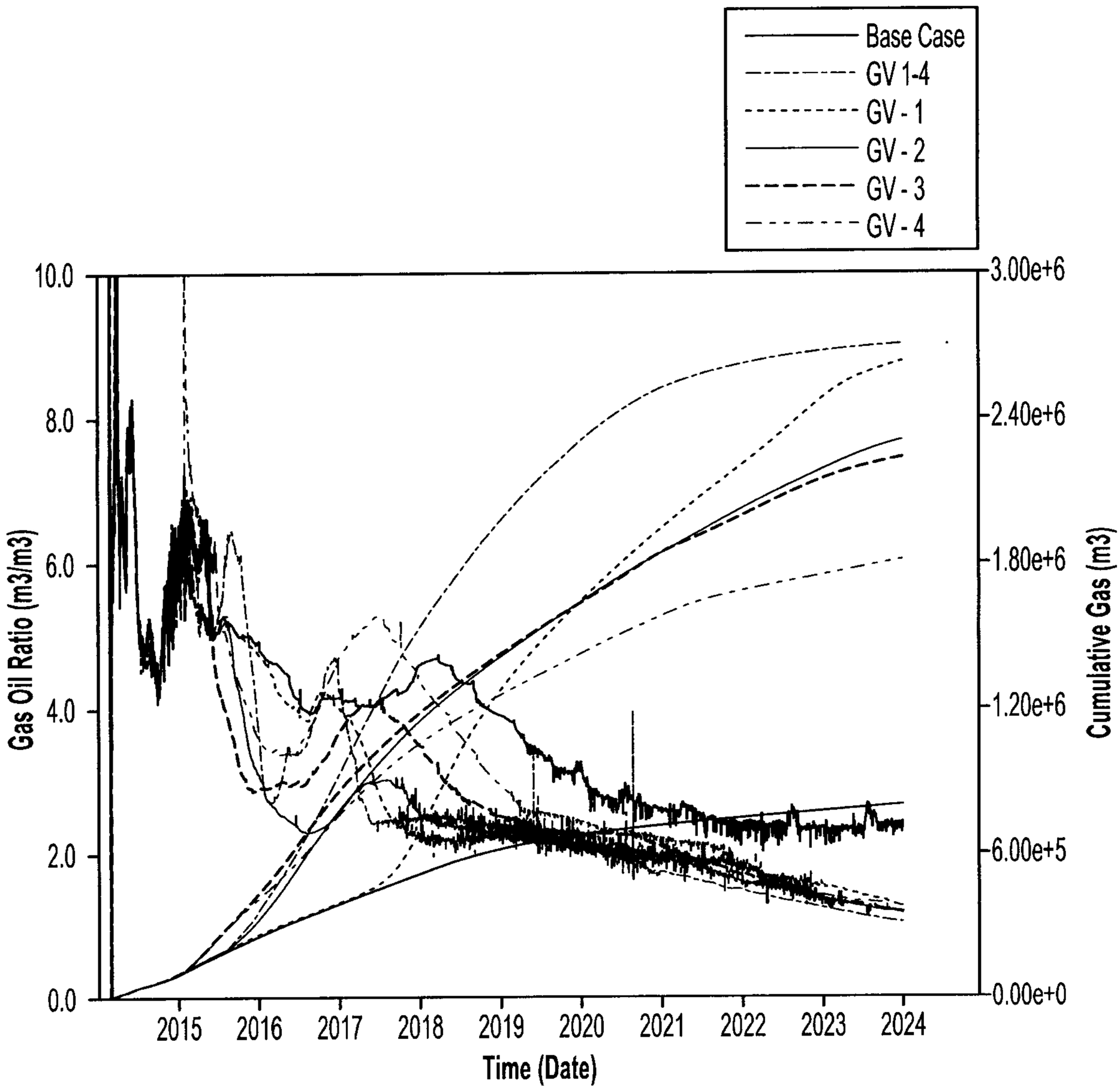

Base Case
GV 1-4
GV - 1
GV - 2
GV - 3
GV - 4
10.0
8.0
6.0
4.0
2.0
0.0
Gas Oil Ratio (m3/m3)
3.00e+6
2.40e+6
1.80e+6
1.20e+6
6.00e+5
0.00e+0
Cumulative Gas (m3)
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Time (Date)

FIG. 44

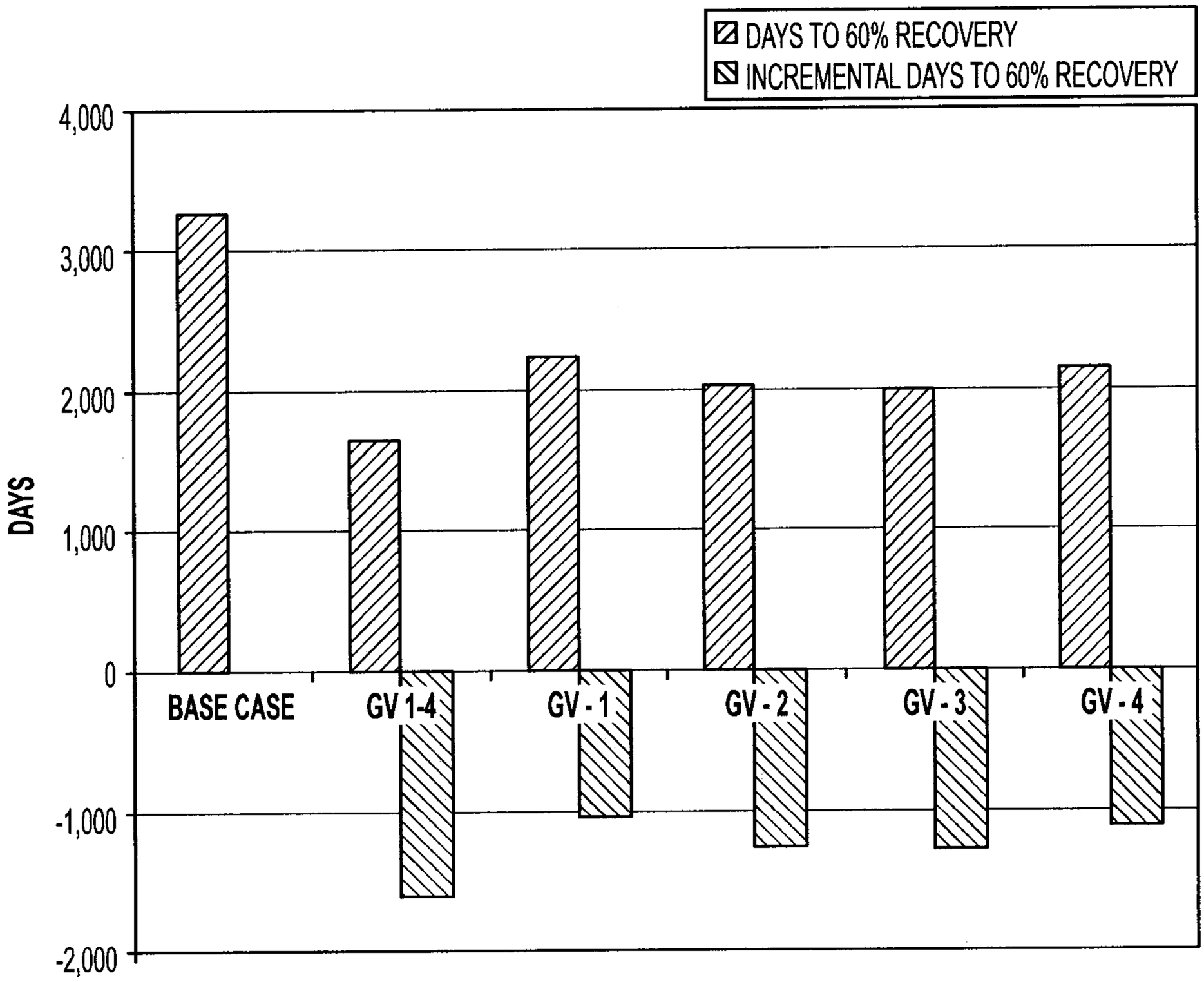

DAYS TO 60% RECOVERY
INCREMENTAL DAYS TO 60% RECOVERY
4,000
3,000
2,000
1,000
0
-1,000
-2,000
DAYS
BASE CASE
GV 1-4
GV - 1
GV - 2
GV - 3
GV - 4

FIG. 45

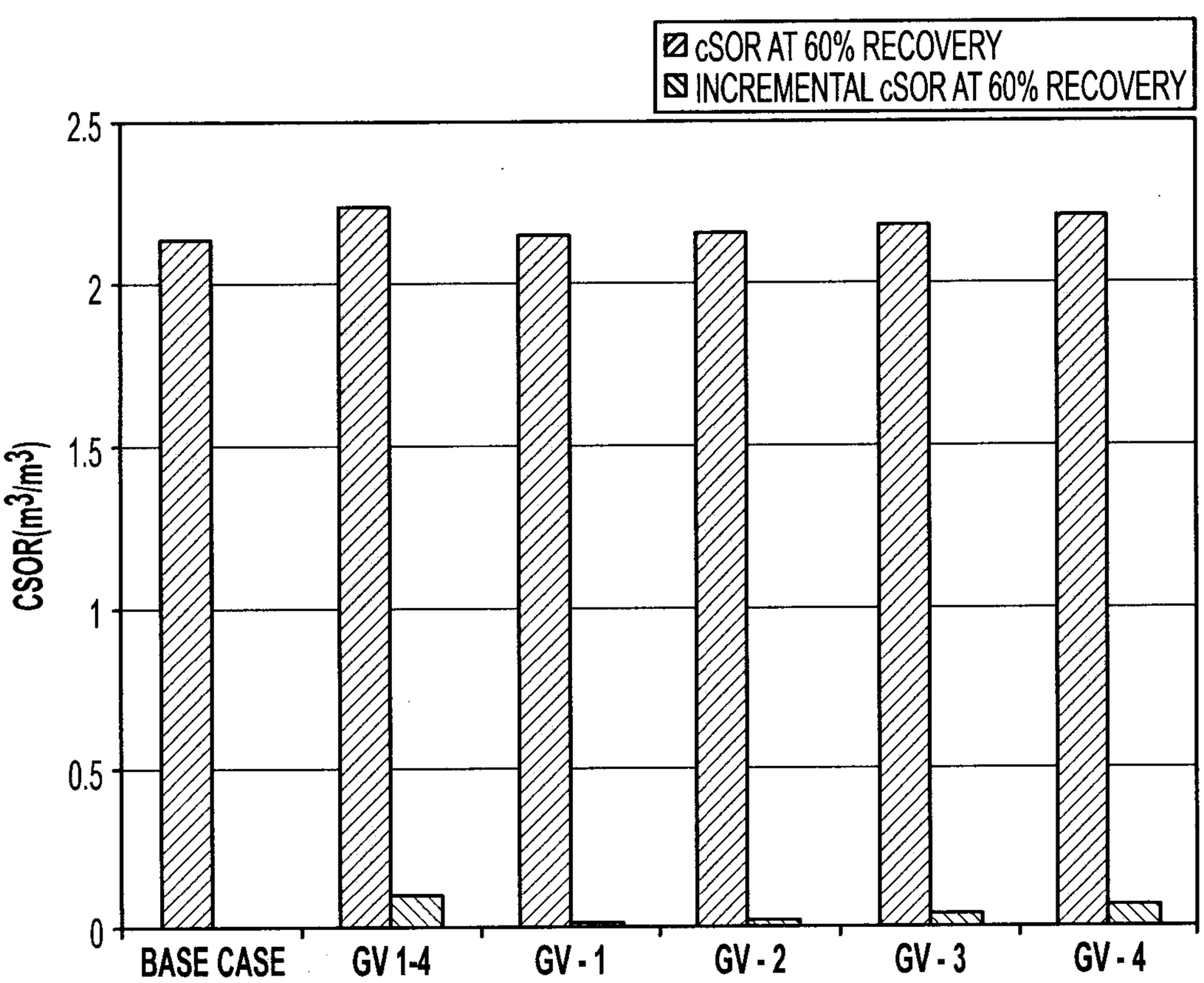

cSOR AT 60% RECOVERY
INCREMENTAL cSOR AT 60% RECOVERY
2.5
2
1.5
1
0.5
0
CSOR(m3/m3)
BASE CASE
GV 1-4
GV - 1
GV - 2
GV - 3
GV - 4

FIG. 46

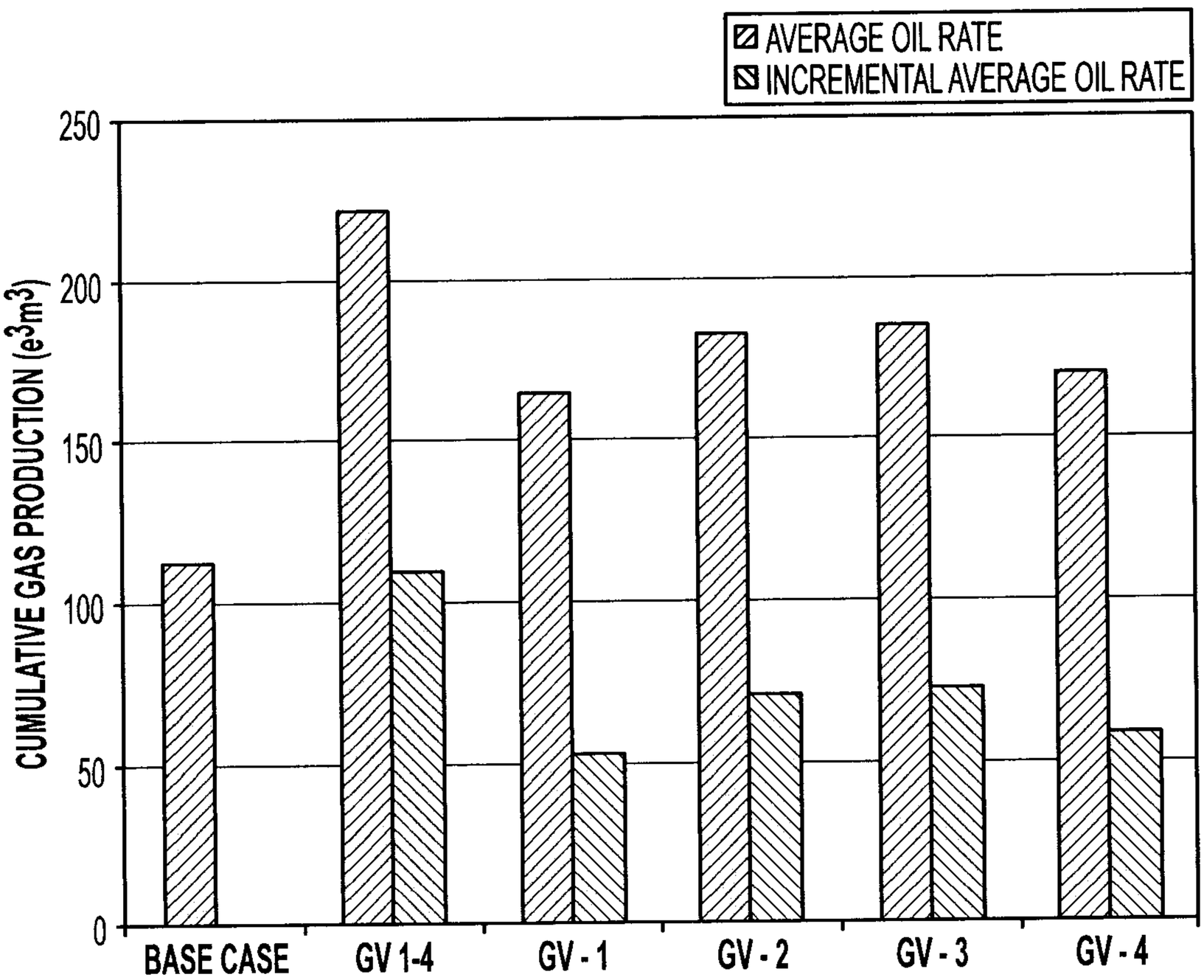

AVERAGE OIL RATE
INCREMENTAL AVERAGE OIL RATE
CUMULATIVE GAS PRODUCTION (e^3m^3)
250
200
150
100
50
0
BASE CASE
GV 1-4
GV - 1
GV - 2
GV - 3
GV - 4

FIG. 47

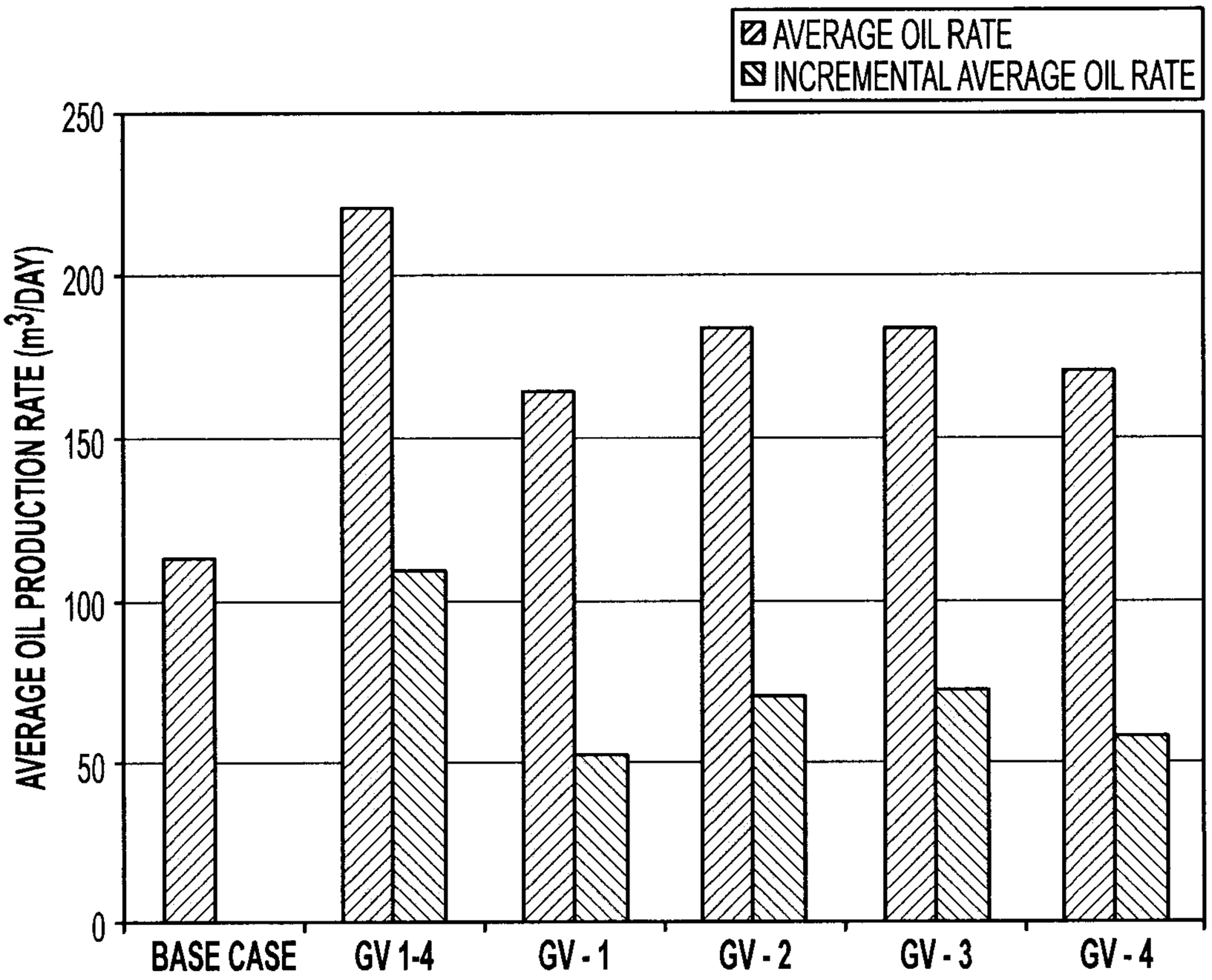

AVERAGE OIL RATE
INCREMENTAL AVERAGE OIL RATE
AVERAGE OIL PRODUCTION RATE (m3/DAY)
250
200
150
100
50
0
BASE CASE
GV 1-4
GV - 1
GV - 2
GV - 3
GV - 4

FIG. 48

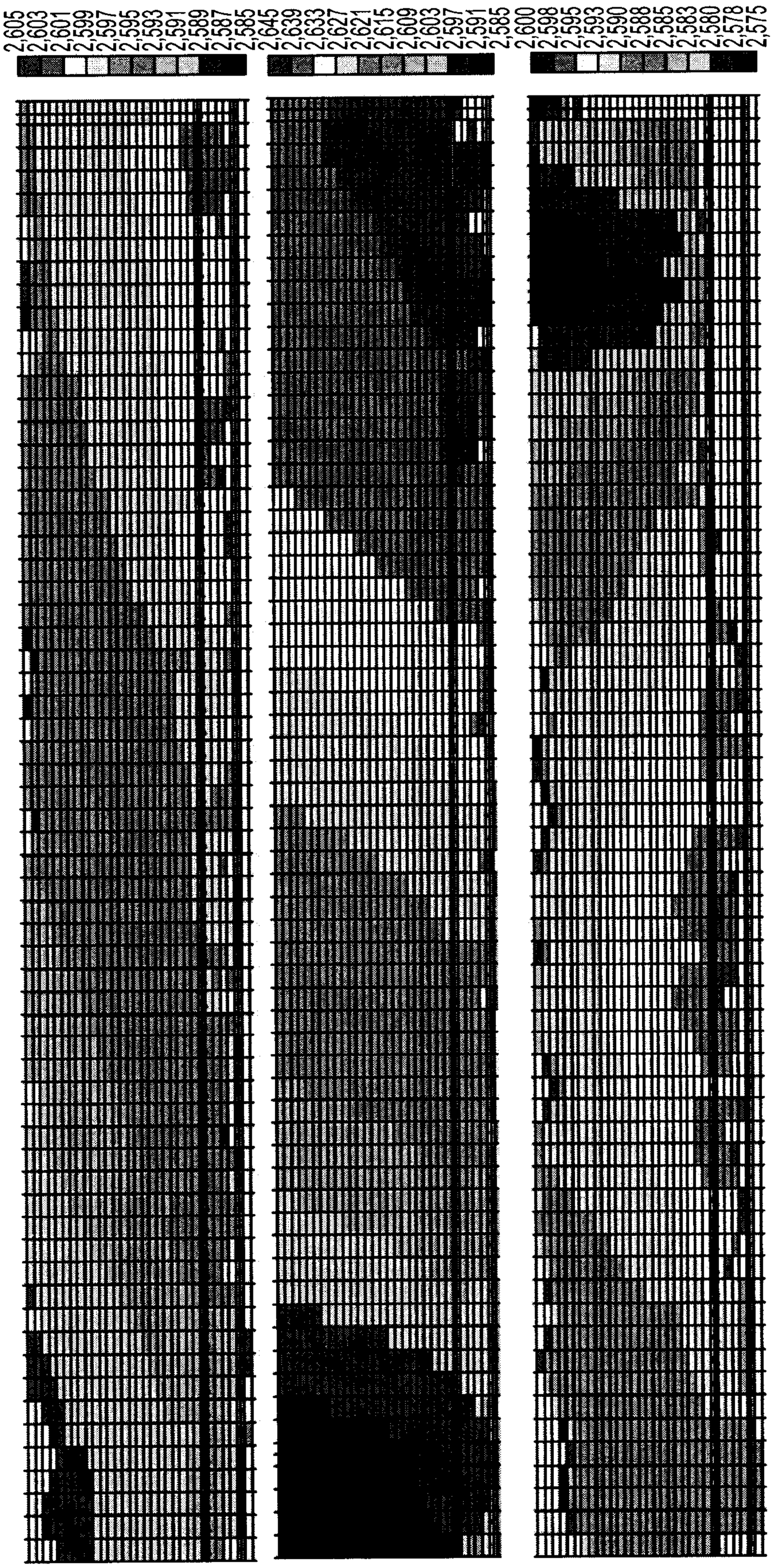

2,605
2,603
2,601
2,599
2,597
2,595
2,593
2,591
2,589
2,587
2,585
2,645
2,639
2,633
2,627
2,621
2,615
2,609
2,603
2,597
2,591
2,585
2,600
2,598
2,595
2,593
2,590
2,588
2,585
2,583
2,580
2,578
2,575

FIG. 49

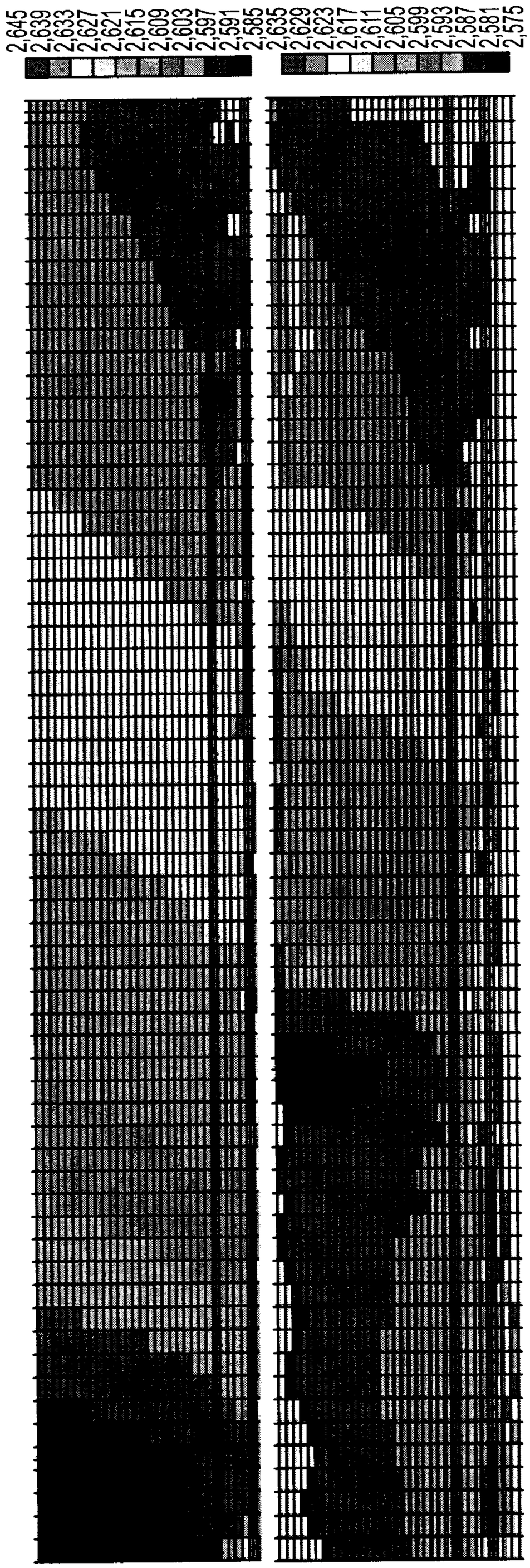

2,645
2,639
2,633
2,627
2,621
2,615
2,609
2,603
2,597
2,591
2,585
2,635
2,629
2,623
2,617
2,611
2,605
2,599
2,593
2,587
2,581
2,575

FIG. 50

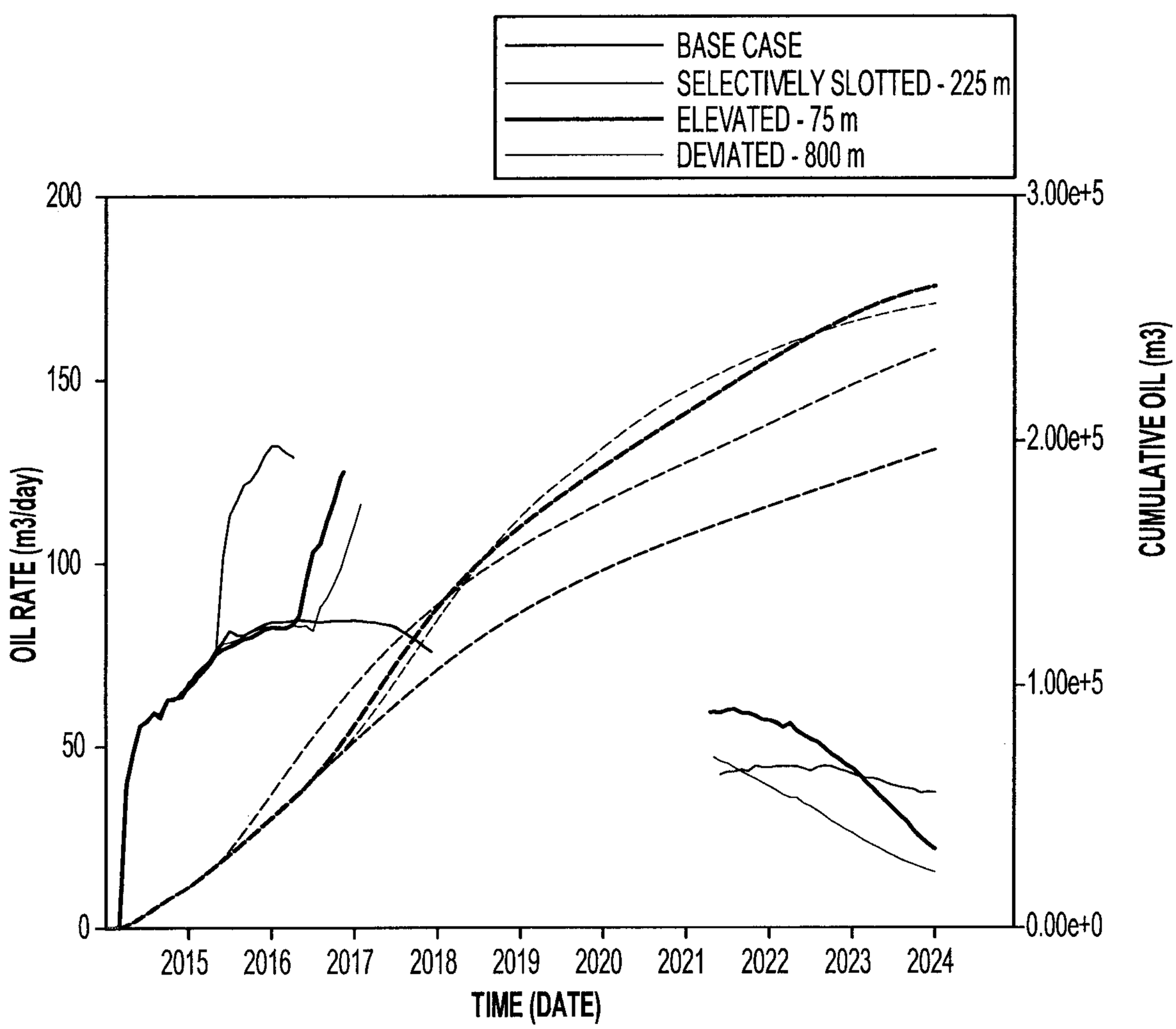

BASE CASE
SELECTIVELY SLOTTED - 225 m
ELEVATED - 75 m
DEVIATED - 800 m
200
150
100
50
0
OIL RATE (m3/day)
3.00e+5
2.00e+5
1.00e+5
0.00e+0
CUMULATIVE OIL (m3)
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
TIME (DATE)

FIG. 51

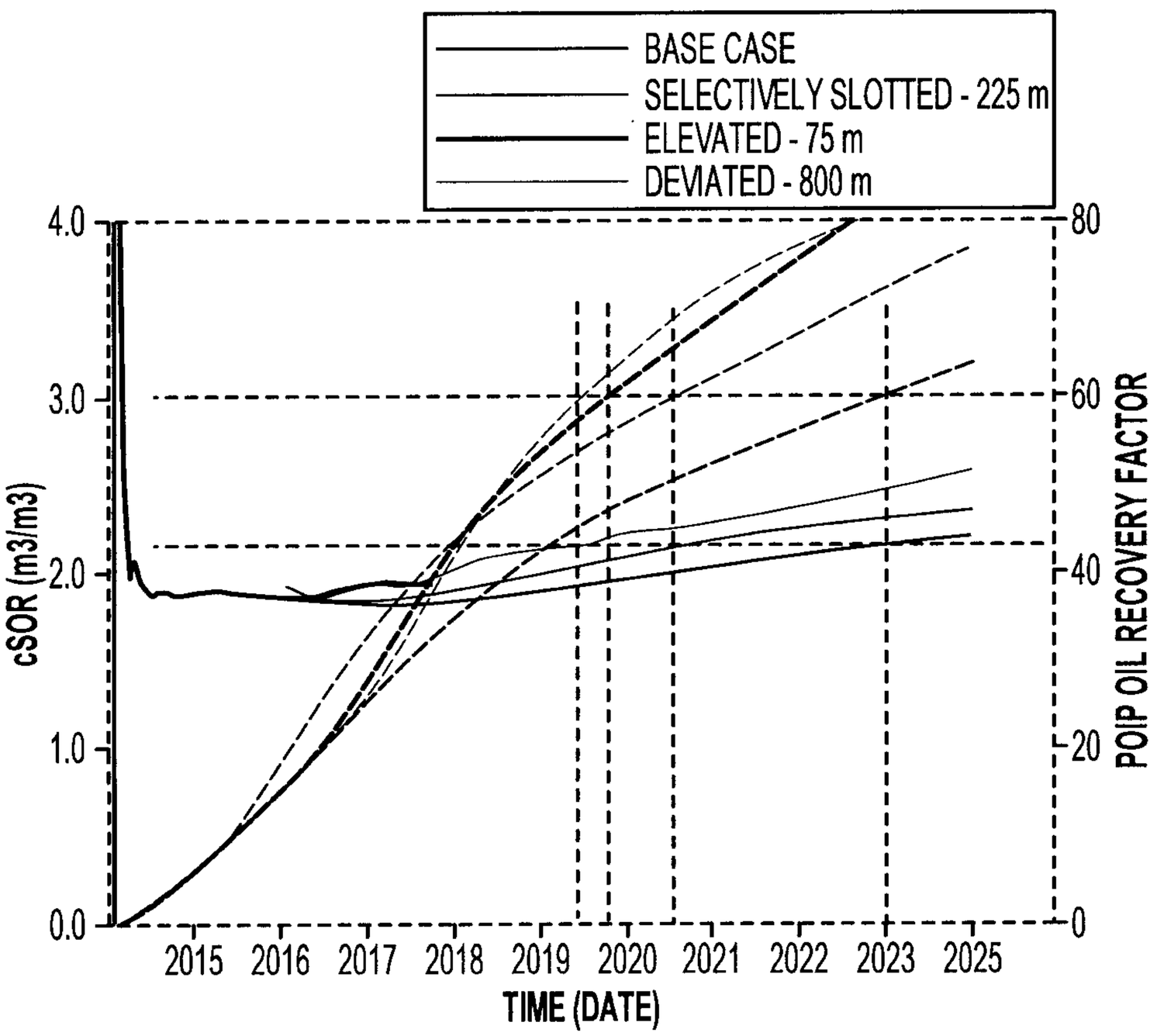

BASE CASE
SELECTIVELY SLOTTED - 225 m
ELEVATED - 75 m
DEVIATED - 800 m
4.0
3.0
2.0
1.0
0.0
cSOR (m3/m3)
80
60
40
20
0
POIP OIL RECOVERY FACTOR
2015
2016
2017
2018
2019
2020
2021
2022
2023
2025
TIME (DATE)

FIG. 52

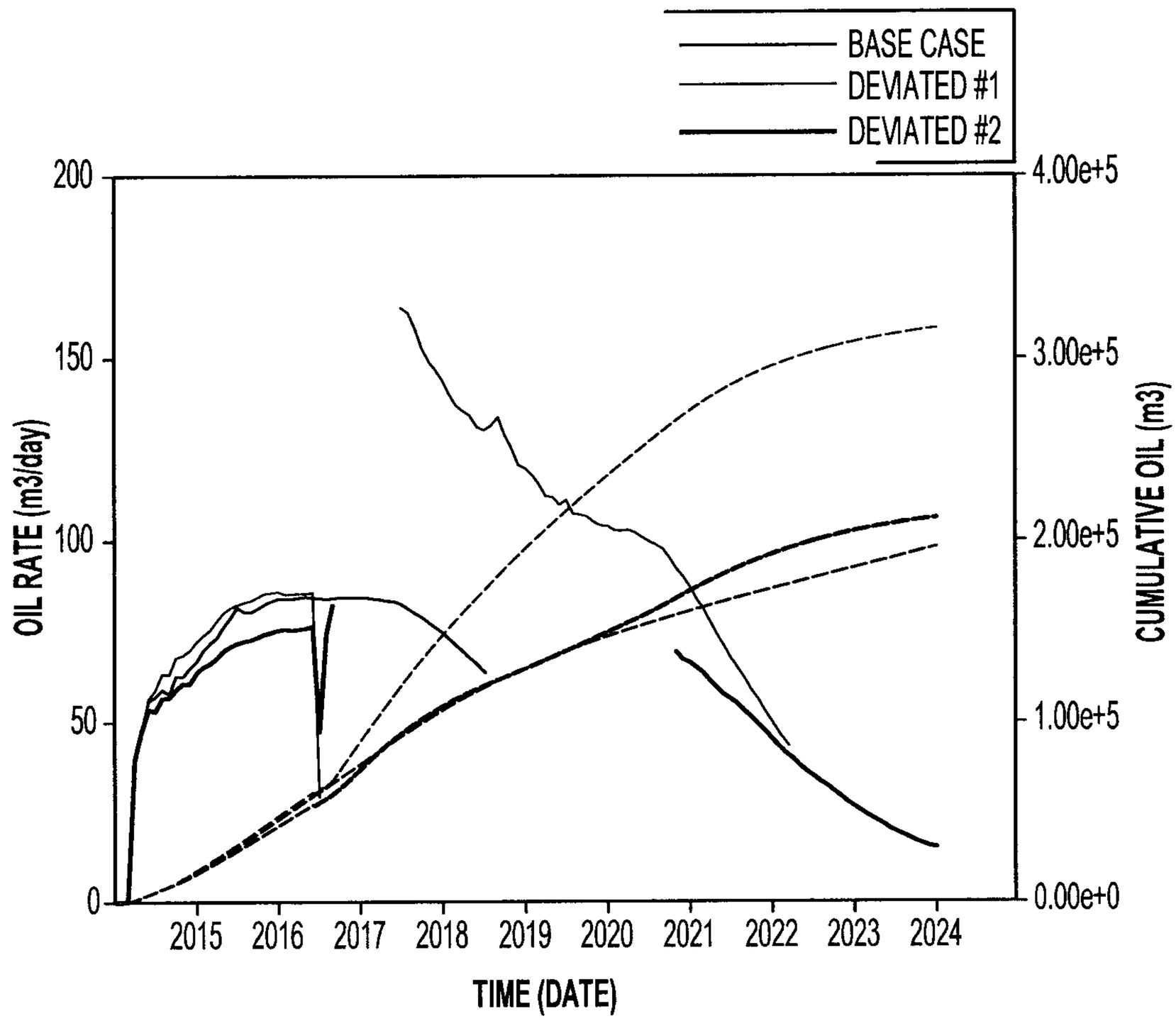

BASE CASE
DEVIATED #1
DEVIATED #2
200
150
100
50
0
OIL RATE (m3/day)
4.00e+5
3.00e+5
2.00e+5
1.00e+5
0.00e+0
CUMULATIVE OIL (m3)
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
TIME (DATE)

FIG. 53

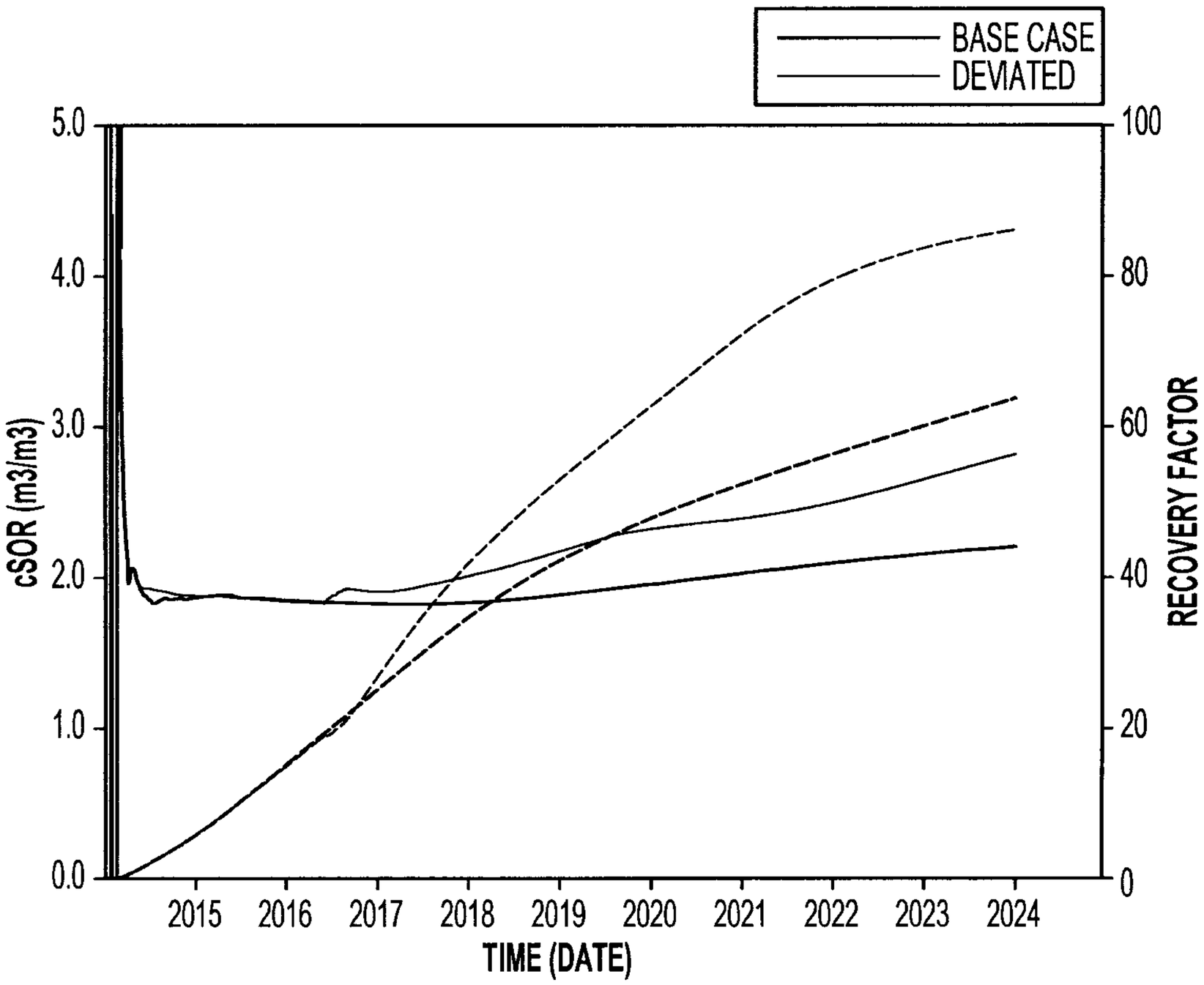
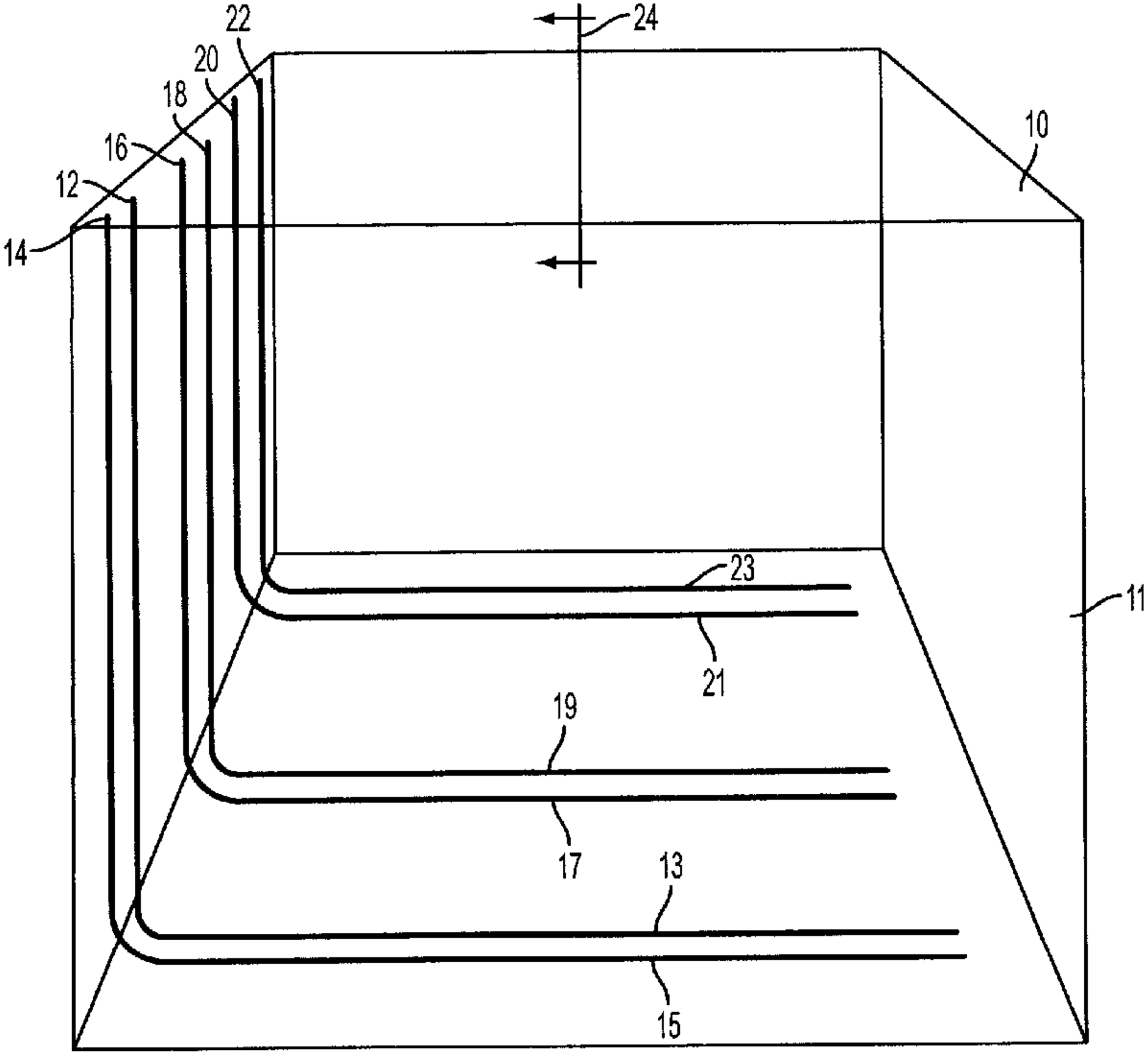

BASE CASE
DEVIATED
5.0
4.0
3.0
2.0
1.0
0.0
cSOR (m3/m3)
100
80
60
40
20
0
RECOVERY FACTOR
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
TIME (DATE)

FIG. 54


22
24
20
18
10
16
12
14
23
11
21
19
17
13
15