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(72) Inventeur/Inventor:
CHAKRABARTY, TAPANTOSH, CA

(73) Propriétaire/Owner:
IMPERIAL OIL RESOURCES LIMITED, CA

(74) Agent: BORDEN LADNER GERVAIS LLP

(54) Titre : COMPOSITION DE MOBILISATION POUR UN PROCEDE D'EVACUATION PAR GRAVITE SERVANT A RECUPERER L'HUILE VISQUEUSE ET COMPOSITION DE DEMARRAGE POUR PHASE DE DEMARRAGE D'UN PROCEDE DE RECUPERATION D'HUILE VISQUEUSE DANS UN RESERVOIR SOUTERRAIN

(54) Title: MOBILIZING COMPOSITION FOR USE IN GRAVITY DRAINAGE PROCESS FOR RECOVERING VISCOUS OIL AND START-UP COMPOSITION FOR USE IN A START-UP PHASE OF A PROCESS FOR RECOVERING VISCOUS OIL FROM AN UNDERGROUND RESERVOIR

(57) **Abrégé/Abstract:**

Generally, described herein is a mobilizing composition for use in a gravity drainage process for recovering viscous oil from an underground reservoir. The mobilizing composition may comprise (i) 75-98 vol. % diluting agent; (ii) 2-25 vol. % steam having a steam quality of at least 5%; and (iii) 0-5 vol. % accelerating agent for accelerating penetration of the diluting agent into the viscous oil. Also generally described herein is a start-up composition for use in a start-up phase of a process for recovering viscous oil from an underground reservoir. The start-up composition comprises (i) 74.9-97.9 vol. % diluting agent; (ii) 2-25 vol. % steam having a steam quality of at least 5%; and (iii) 0.1-5 vol. % accelerating agent for accelerating penetration of the diluting agent into the viscous oil.



ABSTRACT

Generally, described herein is a mobilizing composition for use in a gravity drainage process for recovering viscous oil from an underground reservoir. The mobilizing composition may comprise (i) 75-98 vol. % diluting agent; (ii) 2-25 vol. % steam having a steam quality of at least 5%; and (iii) 0-5 vol. % accelerating agent for accelerating penetration of the diluting agent into the viscous oil.

Also generally described herein is a start-up composition for use in a start-up phase of a process for recovering viscous oil from an underground reservoir. The start-up composition comprises (i) 74.9-97.9 vol. % diluting agent; (ii) 2-25 vol. % steam having a steam quality of at least 5%; and (iii) 0.1-5 vol. % accelerating agent for accelerating penetration of the diluting agent into the viscous oil.

**MOBILIZING COMPOSITION FOR USE IN GRAVITY DRAINAGE PROCESS
FOR RECOVERING VISCOUS OIL
AND
START-UP COMPOSITION FOR USE IN A START-UP PHASE OF A PROCESS FOR
RECOVERING VISCOUS OIL FROM AN UNDERGROUND RESERVOIR**

FIELD OF THE INVENTION

MOBILIZING COMPOSITION

[0001] The disclosure relates generally to hydrocarbon recovery from underground reservoirs. More specifically, the disclosure relates to mobilizing compositions for use in gravity drainage processes for recovering viscous oil and to the processes themselves.

START-UP COMPOSITION

[0002] The disclosure also relates generally to hydrocarbon recovery from underground reservoirs. More specifically, the disclosure relates to start-up compositions for use in a start-up phase of a process for recovering viscous oil.

BACKGROUND OF THE INVENTION

MOBILIZING COMPOSITION

[0003] This section is intended to introduce various aspects of the art, which may be associated with the present disclosure. This discussion is believed to assist in providing a framework to facilitate a better understanding of particular aspects of the present disclosure. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

[0004] Modern society is greatly dependent on the use of hydrocarbon resources for fuels and chemical feedstocks. Hydrocarbons are generally found in subsurface formations that can be termed "reservoirs". Removing hydrocarbons from the reservoirs depends on numerous physical properties of the subsurface formations, such as the permeability of the rock containing the hydrocarbons, the ability of the hydrocarbons to flow through the subsurface formations, and the proportion of hydrocarbons present, among other things. Easily harvested sources of hydrocarbons are dwindling, leaving less accessible sources to

satisfy future energy needs. As the prices of hydrocarbons increase, the less accessible sources become more economically attractive.

[0005] Recently, the harvesting of oil sands to remove heavy oil has become more economical. Hydrocarbon removal from oil sands may be performed by several techniques. For example, a well can be drilled to an oil sand reservoir and steam, hot gas, solvents, or a combination thereof, can be injected to release the hydrocarbons. The released hydrocarbons may be collected by wells and brought to the surface.

[0006] Bitumen and heavy oil (collectively referred to herein as "viscous oil" as further defined below) reserves exist at varying depths beneath the earth's surface. More shallow reserves are often mined followed by surface extraction. Deeper reserves are often exploited by in situ processes.

[0007] Diluting agents have been used for both in situ and surface extraction processes to dilute viscous oil. The term "solvent" is often used in the industry and literature in place of "diluting agent".

[0008] Diluting agents reduce the viscosity of viscous oil by dilution, while steam reduces the viscosity of viscous oil by raising the viscous oil temperature. Reducing the viscosity of in situ viscous oil is done to permit or facilitate its production.

[0009] Where deposits lie well below the surface, viscous oil may be extracted using in situ ("in place") processes. Thermal recovery processes are one category of in situ processes, where steam is used to reduce the viscosity of the viscous oil. These processes are referred to as steam-based processes. One example of an in situ thermal process is the steam-assisted gravity drainage method (SAGD). In SAGD, directional drilling is employed to place two horizontal wells in the oil sands – a lower well and an upper well positioned above it. Steam is injected into the upper well to heat the bitumen and lower its viscosity. The bitumen and condensed steam will then drain downward through the reservoir under the action of gravity and flow into the lower production well, whereby these liquids can be pumped to the surface. At the surface of the well, the condensed steam and bitumen are separated, and the bitumen is diluted with appropriate light hydrocarbons for transport to a refinery or an upgrader. An example of SAGD is described in U.S. Patent No. 4,344,485 (Butler).

[0010] Cyclic Steam Stimulation (CSS) is a thermal recovery process in which the same well is used both for injecting a fluid and for producing oil. In CSS, cycles of steam

injection, soak, and oil production are employed. Once the production rate falls to a given level, the well is put through another cycle of injection, soak, and production. An example of CSS is described in U.S. Patent No. 4,280,559 (Best).

[0011] Steam Flooding (SF) is an in situ thermal process that involves injecting steam into the formation through an injection well. Steam moves through the formation, mobilizing oil as it flows toward the production well. Mobilized oil is swept to the production well by the steam drive. An example of steam flooding is described in U.S. Patent No. 3,705,625 (Whitten).

[0012] Other steam-based thermal processes include Solvent-Assisted Steam-Assisted Gravity Drainage (SA-SAGD), an example of which is described in Canadian Patent No. 1,246,993 (Vogel); Liquid Addition to Steam for Enhanced Recovery (LASER), an example of which is described in U.S. Patent No. 6,708,759 (Leaute *et al.*); Combined Steam and Vapour Extraction Process (SAVEX), an example of which is described in U.S. Patent No. 6,662,872 (Guttek *et al.*), and derivatives thereof. These processes employ a "diluting agent" with steam.

[0013] Solvent-dominated recovery processes (SDRPs) are another category of in situ processes, where solvent is used to reduce the viscosity of the viscous oil. At the present time, solvent-dominated recovery processes (SDRPs) are rarely used to produce highly viscous oil. Vapour Extraction (VAPEX) is an example of SDRP, which is described in U.S. Patent No. 5,899,274 (Frauenfeld). In certain described SDRPs, the solvent is heated as in, for example, heated-VAPEX (H-VAPEX), which is VAPEX using a heated diluting agent.

[0014] It is desirable to provide an improved or alternative mobilizing composition for use in gravity drainage processes for recovering viscous oil from an underground reservoir.

START-UP COMPOSITION

[0015] This section is intended to introduce various aspects of the art, which may be associated with the present disclosure. This discussion is believed to assist in providing a framework to facilitate a better understanding of particular aspects of the present disclosure. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

[0016] Modern society is greatly dependent on the use of hydrocarbon resources for fuels and chemical feedstocks. Hydrocarbons are generally found in subsurface formations

that can be termed “reservoirs”. Removing hydrocarbons from the reservoirs depends on numerous physical properties of the subsurface formations, such as the permeability of the rock containing the hydrocarbons, the ability of the hydrocarbons to flow through the subsurface formations, and the proportion of hydrocarbons present, among other things. Easily harvested sources of hydrocarbons are dwindling, leaving less accessible sources to satisfy future energy needs. As the prices of hydrocarbons increase, the less accessible sources become more economically attractive.

[0017] Recently, the harvesting of oil sands to remove heavy oil has become more economical. Hydrocarbon removal from oil sands may be performed by several techniques. For example, a well can be drilled to an oil sand reservoir and steam, hot gas, solvents, or a combination thereof, can be injected to release the hydrocarbons. The released hydrocarbons may be collected by wells and brought to the surface.

[0018] Bitumen and heavy oil (collectively referred to herein as “viscous oil” as further defined below) reserves exist at varying depths beneath the earth’s surface. More shallow reserves are often mined followed by surface extraction. Deeper reserves are often exploited by in situ processes. Where deposits lie well below the surface, viscous oil may be extracted using in situ (“in place”) techniques.

[0019] Diluting agents have been used for both in situ and surface extraction processes to dilute viscous oil. The term “solvent” is often used in the industry and literature in place of “diluting agent”. Diluting agents that have previously been suggested for viscous oil recovery include n-alkanes, such as ethane, propane, and butane, n- and iso-pentane, cycloalkanes like cyclopentane and cyclohexane, and gas plant condensates (a mixture of n-alkanes, naphthenes and aromatics).

[0020] Diluting agents reduce the viscosity of viscous oil by dilution, while steam reduces the viscosity of viscous oil by raising the viscous oil temperature. Reducing the viscosity of in situ viscous oil is done to permit or facilitate its production.

[0021] Where deposits lie well below the surface, viscous oil may be extracted using in situ (“in place”) processes. Thermal recovery processes are one category of in situ thermal processes, where steam is used to reduce the viscosity of the viscous oil. These processes are referred to as steam-based processes. One example of an in situ thermal process is the steam-assisted gravity drainage method (SAGD). In SAGD, directional drilling is employed to place two horizontal wells in the oil sands – a lower well and an upper well positioned above

it. Steam is injected into the upper well to heat the bitumen and lower its viscosity. The bitumen and condensed steam will then drain downward through the reservoir under the action of gravity and flow into the lower production well, whereby these liquids can be pumped to the surface. At the surface of the well, the condensed steam and bitumen are separated, and the bitumen is diluted with appropriate light hydrocarbons for transport to a refinery or an upgrader. An example of SAGD is described in U.S. Patent No. 4,344,485 (Butler).

[0022] In other in situ thermal processes, such as in Cyclic Steam Stimulation (CSS), the same well is used both for injecting a fluid and for producing oil. In CSS, cycles of steam injection, soak, and oil production are employed. Once the production rate falls to a given level, the well is put through another cycle of injection, soak, and production. An example of CSS is described in U.S. Patent No. 4,280,559 (Best).

[0023] Steam Flooding (SF) is an in situ thermal process that involves injecting steam into the formation through an injection well. Steam moves through the formation, mobilizing oil as it flows toward the production well. Mobilized oil is swept to the production well by the steam drive. An example of steam flooding is described in U.S. Patent No. 3,705,625 (Whitten).

[0024] Another in situ thermal processes include Solvent-Assisted Steam-Assisted Gravity Drainage (SA-SAGD), an example of which is described in Canadian Patent No. 1,246,993 (Vogel); Liquid Addition to Steam for Enhanced Recovery (LASER), an example of which is described in U.S. Patent No. 6,708,759 (Leaute *et al.*); Combined Steam and Vapour Extraction Process (SAVEX), an example of which is described in U.S. Patent No. 6,662,872 (Gutek *et al.*); and derivatives thereof. These processes employ a relatively small amount of solvent or "diluting agent" in steam-dominated recovery processes

[0025] Solvent-dominated recovery processes (SDRPs) are another category of in situ processes, where solvent is used to reduce the viscosity of the viscous oil. At the present time, solvent-dominated recovery processes (SDRPs) are rarely used to produce highly viscous oil. Vapour Extraction (VAPEX) is an example of SDRP, which is described in U.S. Patent No. 5,899,274 (Frauenfeld). In certain described SDRPs, the solvent is heated. Heated-VAPEX (H-VAPEX) is VAPEX using a heated diluting agent.

[0026] Cyclic solvent-dominated recovery processes (CSDRPs) have also been proposed. CSDRPs are a subset of SDRPs. A CSDRP may be, but is not necessarily, a

generally non-thermal recovery method that uses a solvent (or “diluting agent”) to mobilize viscous oil by cycles of injection and production. In a CSDRP, a viscosity-reducing solvent is injected through a well into a subterranean viscous-oil reservoir, causing the pressure to increase. Next, the pressure is lowered and reduced-viscosity oil is produced to the surface through the same well through which the solvent was injected. Multiple cycles of injection and production are used. In some instances, a well may not undergo cycles of injection and production, but only cycles of injection or only cycles of production. CSDRPs may be particularly attractive for thinner or lower-oil-saturation reservoirs. In such reservoirs, thermal methods utilizing heat to reduce viscous oil viscosity may be inefficient due to excessive heat loss to the overburden and/or underburden and/or reservoir with low oil content. References describing specific CSDRPs include: Canadian Patent No. 2,349,234 (Lim *et al.*); Lim *et al.*, “Three-dimensional Scaled Physical Modeling of Solvent Vapour Extraction of Cold Lake Bitumen”, *The Journal of Canadian Petroleum Technology*, 35(4), pp. 32-40, April 1996; Lim *et al.*, “Cyclic Stimulation of Cold Lake Oil Sand with Supercritical Ethane”, *SPE Paper* 30298, 1995; US Patent No. 3,954,141 (Allen *et al.*); and Feali *et al.*, “Feasibility Study of the Cyclic VAPEX Process for Low Permeable Carbonate Systems”, *International Petroleum Technology Conference Paper* 12833, 2008. The family of processes within the Lim *et al.* references describes embodiments of a particular SDRP that is also a cyclic solvent-dominated recovery process (CSDRP). These processes relate to the recovery of heavy oil and bitumen from subterranean reservoirs using cyclic injection of a solvent in the liquid state which vapourizes upon production. The family of processes within the Lim *et al.* references may be referred to as CSPTM processes. Another example of a CSDRP is described in Canadian Patent Document No. 2,688,392 (Lebel *et al.*, published June 9, 2011).

[0027] In certain predominantly non-thermal CSDRPs, while heat is not used to reduce the viscosity of the viscous oil, the use of heat is not excluded. Heating may be beneficial to improve performance or start-up. For start-up, low-level heating (for example, less than 100°C) may be appropriate. Low-level heating of the solvent prior to injection may also be performed to prevent hydrate formation in tubulars and in the reservoir. Heating to higher temperatures may also benefit recovery.

[0028] Before commencing an in situ process, a start-up phase may occur. The start-up phase may condition the reservoir for viscous oil extraction and production by the

recovery processes. Without a start-up phase, viscous oil may be too viscous and immobile. Consequently, it may be difficult for an extraction fluid to penetrate a viscous oil-containing region, to the extent required for a steam-based or solvent-dominated viscous oil recovery process.

[0029] Some start-up phases for SAGD use heat circulation. For example, steam and surfactant may be used to create a foam, as disclosed in US Patent 5,215,146, a heated fluid may be injected, as disclosed in WO 1999/067503 or CA 2,697,417, or the wellbores may be presoaked as disclosed in WO 2012/037147 or US 2011/0174488.

[0030] Another start-up phase for SAGD, disclosed in CA 2,766,838, discloses wellbore pair configured to force an initial fluid communication between the production wellbore and the injection wellbore to occur at a selected region along the production wellbore and injection wellbore.

[0031] Another start-up phase for SAGD, disclosed in CA 2,740,941, discloses relying on the injection of a start-up fluid at elevated pressures in the injection wellbore. A production wellbore is used to create a pressure sink (voidage) to maximize the available pressure gradient between the production and injection wellbores and as a result help draw the start-up fluid towards the production wellbore. The process is applied after the production wellbore has been completed with production tubing, artificial lift has been installed or is operational. Measuring the reproduced start-up fluid and storing or transporting the produced fluids once they are produced to surface are described. The volume of start-up fluid required is substantial, with the representative calculations suggesting required start-up fluid volumes of 500-18,000 meters cubed (m^3) to treat a single wellbore pair. A single wellbore pair includes a single production wellbore and a single injection wellbore.

[0032] WO 2012/121711 discloses delivering a small reduction in the time duration of the start-up phase time requirements and no real capital cost reduction benefits as the equipment required to circulate steam in the extraction process of heavy oil must be in place before the start-up phase. WO 2012/121711 discloses fluid circulation followed by a "squeeze step" (described as the shut-off of fluid returns in a wellbore and the inspection of an increase in fluid production at another wellbore).

[0033] WO 2013/071434 discloses that in order to accelerate the start-up phase of a SAGD wellbore pair, it is preferable to establish a physical connection between the injection and production wellbores. The physical connection can be established by: (1) drilling the

injection and production wellbores such that the toes of wellbores intercept; (2) drilling a vertical wellbore that intercepts the toe locations of the injection and production wellbores (creating the physical connection via it's wellbore); or (3) propagating a fracture between the toe locations of the injection and production wellbores. Thus, WO 2013/071434 discloses that, by creating a physical connection (or a high permeability path by fracturing), it is possible to create a continuous unidirectional pathway between the injection and production wellbores for the heated fluids used to start-up the wellbores. At the end of the start-up phase, it may then be necessary to plug the intersection point connecting the injection and production wellbores. Hence, the start-up phase disclosed in WO 2013/071434 may be complex and expensive to implement.

[0034] CA 2,698,898 discloses a method of initiating or accelerating fluid communication between horizontal wellbores located in a formation of very limited fluid mobility at start-up. A selected amount of a diluent such as xylene, benzene, toluene or phenol, is injected at sub-fracturing conditions and ambient temperature into a first of the wellbores. The method may be employed for a start-up phase for the recovery of heavy oil using, for example, steam-assisted gravity drainage.

[0035] It is desirable to provide an improved or alternative start-up composition for use in a start-up phase of a process for recovering viscous oil from an underground reservoir.

SUMMARY OF THE INVENTION

MOBILIZING COMPOSITION

[0036] Generally, described herein is a mobilizing composition for use in a gravity drainage process for recovering viscous oil from an underground reservoir. The mobilizing composition may comprise (i) 75-98 vol. % diluting agent; (ii) 2-25 vol. % steam having a steam quality of at least 5%; and (iii) 0-5 vol. % accelerating agent for accelerating penetration of the diluting agent into the viscous oil.

START-UP COMPOSITION

[0037] Generally, described herein is a start-up composition for use in a start-up phase of a process for recovering viscous oil from an underground reservoir. The start-up composition comprises (i) 74.9-97.9 vol. % diluting agent; (ii) 2-25 vol. % steam having a

steam quality of at least 5%; and (iii) 0.1-5 vol. % accelerating agent for accelerating penetration of the diluting agent into the viscous oil.

[0038] Other aspects and features of the present invention will become apparent to those ordinarily skilled in the art upon review of the following description of specific embodiments of the invention in conjunction with the accompanying figures.

BRIEF DESCRIPTION OF THE DRAWINGS

MOBILIZING COMPOSITION

[0039] These and other features, aspects and advantages of the disclosure will become apparent from the following description, appending claims and the accompanying drawings, which are briefly described below.

[0040] Fig. 1 is a flow chart of a gravity drainage process for recovering viscous oil from an underground reservoir.

[0041] Figs 2 to 12 depict simulation results.

[0042] Fig. 2 is a graph illustrating penetrating rate.

[0043] Fig. 3 is a graph illustrating bitumen rate.

[0044] Fig. 4 is a graph illustrating % increase in cumulative bitumen.

[0045] Fig. 5 is a graph illustrating bitumen rate increase.

[0046] Fig. 6 is a graph illustrating C7 injection rate.

[0047] Fig. 7 is a graph illustrating % decrease in cumulative C7 injection.

[0048] Fig. 8 is a graph illustrating diluting agent recovery.

[0049] Fig. 9 is a graph illustrating bitumen recover per diluting agent left in the reservoir.

[0050] Fig. 10 illustrates two vapor chambers.

[0051] Fig. 11 illustrates two temperature fronts.

[0052] Fig. 12 illustrates C7 advancement in a reservoir.

START-UP COMPOSITION

[0053] Fig. 13 is a flow chart of a gravity drainage process for recovering viscous oil from an underground reservoir.

[0054] Figs 14 to 18 depict simulation results.

[0055] Fig. 14 is a graph illustrating penetrating rate.

[0056] Fig. 15 is a graph illustrating bitumen rate.

- [0057] Fig. 16 illustrates two vapour chambers at 150 days.
- [0058] Fig. 17 illustrates two vapour chambers at 190 days.
- [0059] Fig. 18 is a graph illustrating % increase in cumulative bitumen.
- [0060] It should be noted that the figures are merely examples and no limitations on the scope of the present disclosure are intended thereby. Further, the figures are generally not drawn to scale, but are drafted for purposes of convenience and clarity in illustrating various aspects of the disclosure.

DETAILED DESCRIPTION

[0061] For the purpose of promoting an understanding of the principles of the disclosure, reference will now be made to the features illustrated in the drawings and specific language will be used to describe the same. It will nevertheless be understood that no limitation of the scope of the disclosure is thereby intended. Any alterations and further modifications, and any further applications of the principles of the disclosure as described herein are contemplated as would normally occur to one skilled in the art to which the disclosure relates. It will be apparent to those skilled in the relevant art that some features that are not relevant to the present disclosure may not be shown in the drawings for the sake of clarity.

[0062] At the outset, for ease of reference, certain terms used in this application and their meaning, as used in this context, are set forth below. To the extent a term used herein is not defined below, it should be given the broadest definition persons in the pertinent art have given that term as reflected in at least one printed publication or issued patent. Further, the present processes are not limited by the usage of the terms shown below, as all equivalents, synonyms, new developments and terms or processes that serve the same or a similar purpose are considered to be within the scope of the present disclosure.

[0063] A "hydrocarbon" is an organic compound that primarily includes the elements of hydrogen and carbon, although nitrogen, sulfur, oxygen, metals, or any number of other elements may be present in small amounts. Hydrocarbons generally refer to components found in heavy oil or in oil sands. Hydrocarbon compounds may be aliphatic or aromatic, and may be straight chained, branched, or partially or fully cyclic.

[0064] "Bitumen" is a naturally occurring heavy oil material. Generally, it is the hydrocarbon component found in oil sands. Bitumen can vary in composition depending

upon the degree of loss of more volatile components. It can vary from a very viscous, tar-like, semi-solid material to solid forms. The hydrocarbon types found in bitumen can include aliphatics, aromatics, resins, and asphaltenes. A typical bitumen might be composed of:

- 19 weight (wt.) percent (%) aliphatics (which can range from 5 wt. % - 30 wt. %, or higher);
- 19 wt. % asphaltenes (which can range from 5 wt. % - 30 wt. %, or higher);
- 30 wt. % aromatics (which can range from 15 wt. % - 50 wt. %, or higher);
- 32 wt. % resins (which can range from 15 wt. % - 50 wt. %, or higher); and
- some amount of sulfur (which can range from 2 to 7 wt. %, or higher).

In addition, bitumen can contain some water and nitrogen compounds ranging from less than 0.4 wt. % to in excess of 0.7 wt. %. The percentage of the hydrocarbon found in bitumen can vary. The term "heavy oil" includes bitumen as well as lighter materials that may be found in a sand or carbonate reservoir.

[0065] "Heavy oil" includes oils which are classified by the American Petroleum Institute ("API"), as heavy oils, extra heavy oils, or bitumens. The term "heavy oil" includes bitumen. Heavy oil may have a viscosity of about 1,000 centipoise (cP) or more, 10,000 cP or more, 100,000 cP or more, or 1,000,000 cP or more. In general, a heavy oil has an API gravity between 22.3° API (density of 920 kilograms per meter cubed (kg/m³) or 0.920 grams per centimeter cubed (g/cm³)) and 10.0° API (density of 1,000 kg/m³ or 1 g/cm³). An extra heavy oil, in general, has an API gravity of less than 10.0° API (density greater than 1,000 kg/m³ or 1 g/cm³). For example, a source of heavy oil includes oil sand or bituminous sand, which is a combination of clay, sand, water and bitumen.

[0066] The term "viscous oil" as used herein means a hydrocarbon, or mixture of hydrocarbons, that occurs naturally and that has a viscosity of at least 10 cP (centipoise) at initial reservoir conditions. Viscous oil includes oils generally defined as "heavy oil" or "bitumen". Bitumen is classified as an extra heavy oil, with an API gravity of about 10° or less, referring to its gravity as measured in degrees on the American Petroleum Institute (API) Scale. Heavy oil has an API gravity in the range of about 22.3° to about 10°. The terms viscous oil, heavy oil, and bitumen are used interchangeably herein since they may be extracted using similar processes.

[0067] In situ is a Latin phrase for "in the place" and, in the context of hydrocarbon recovery, refers generally to a subsurface hydrocarbon-bearing reservoir. For example, in

situ temperature means the temperature within the reservoir. In another usage, an in situ oil recovery technique is one that recovers oil from a reservoir below the earth's surface.

[0068] The term "subterranean formation" refers to the material existing below the earth's surface. The subterranean formation may comprise a range of components, e.g. minerals such as quartz, siliceous materials such as sand and clays, as well as the oil and/or gas that is extracted. The subterranean formation may be a subterranean body of rock that is distinct and continuous. The terms "reservoir" and "formation" may be used interchangeably.

[0069] The terms "approximately," "about," "substantially," and similar terms are intended to have a broad meaning in harmony with the common and accepted usage by those of ordinary skill in the art to which the subject matter of this disclosure pertains. It should be understood by those of skill in the art that these terms are intended to allow a description of certain features described and claimed without restricting the scope of these features to the precise numeral ranges provided. Accordingly, these terms should be interpreted as indicating that insubstantial or inconsequential modifications or alterations of the subject matter described and are considered to be within the scope of the disclosure.

[0070] The articles "the", "a" and "an" are not necessarily limited to mean only one, but rather are inclusive and open ended so as to include, optionally, multiple such elements.

[0071] "At least one," in reference to a list of one or more entities should be understood to mean at least one entity selected from any one or more of the entity in the list of entities, but not necessarily including at least one of each and every entity specifically listed within the list of entities and not excluding any combinations of entities in the list of entities. This definition also allows that entities may optionally be present other than the entities specifically identified within the list of entities to which the phrase "at least one" refers, whether related or unrelated to those entities specifically identified. Thus, as a non-limiting example, "at least one of A and B" (or, equivalently, "at least one of A or B," or, equivalently "at least one of A and/or B") may refer, to at least one, optionally including more than one, A, with no B present (and optionally including entities other than B); to at least one, optionally including more than one, B, with no A present (and optionally including entities other than A); to at least one, optionally including more than one, A, and at least one, optionally including more than one, B (and optionally including other entities). In other words, the phrases "at least one," "one or more," and "and/or" are open-ended expressions that are both conjunctive and disjunctive in operation. For example, each of the expressions "at least

one of A, B and C,” “at least one of A, B, or C,” “one or more of A, B, and C,” “one or more of A, B, or C” and “A, B, and/or C” may mean A alone, B alone, C alone, A and B together, A and C together, B and C together, A, B and C together, and optionally any of the above in combination with at least one other entity.

[0072] Where two or more ranges are used, such as but not limited to 1 to 5 or 2 to 4, any number between or inclusive of these ranges is implied.

[0073] As used herein, the phrase, “for example,” the phrase, “as an example,” and/or simply the term “example,” when used with reference to one or more components, features, details, structures, and/or methods according to the present disclosure, are intended to convey that the described component, feature, detail, structure, and/or method is an illustrative, non-exclusive example of components, features, details, structures, and/or methods according to the present disclosure. Thus, the described component, feature, detail, structure, and/or method is not intended to be limiting, required, or exclusive/exhaustive; and other components, features, details, structures, and/or methods, including structurally and/or functionally similar and/or equivalent components, features, details, structures, and/or methods, are also within the scope of the present disclosure.

MOBILIZING COMPOSITION

[0074] Diluting agents that have previously been suggested for viscous oil recovery include, but are not limited to, n-alkanes, such as ethane, propane, and butane, n- and iso-pentane, cycloalkanes like cyclopentane and cyclohexane, and gas plant condensates (a mixture of n-alkanes, naphthenes and aromatics).

[0075] Described herein is a mobilizing composition for use in a gravity drainage process for recovering viscous oil from an underground reservoir. The mobilizing composition may comprise (i) 75-98 vol. % diluting agent; (ii) 2-25 vol. % steam having a steam quality of at least 5%; and (iii) 0-5 vol. % accelerating agent for accelerating penetration of the diluting agent into the viscous oil. The vol. % in each item is at standard temperature and pressure (STP).

[0076] The diluting agent may comprise a non-polar hydrocarbon with 2 to 30 carbon atoms. The diluting agent may comprise at least 50 wt. % of a non-polar hydrocarbon with 2 to 30 carbon atoms. The diluting agent may comprise a C2-C30 alkane. The diluting agent may comprise at least 50 wt. % of a C2-C30 alkane. The diluting agent may comprise a C2-C30 n-alkane. The diluting agent may comprise at least 50 wt. % of a C2-C30 n-alkane.

The diluting agent may comprise a C2-C20 alkane. The diluting agent may comprise at least 50 wt. % of a C2-C20 alkane. The diluting agent may comprise a C2-C20 n-alkane. The diluting agent may comprise at least 50 wt. % of a C2-C20 n-alkane. The diluting agent may comprise a C2-C5 alkane. The diluting agent may comprise at least 50 wt. % of a C2-C5 alkane. The diluting agent may comprise propane. The diluting agent may comprise at least 50 wt. % propane. The diluting agent may comprise a C5-C7 cycloalkane. The diluting agent may comprise at least 50 wt. % of a C5-C7 cycloalkane. The diluting agent may comprise cyclohexane. The diluting agent may comprise at least 50 wt. % of cyclohexane. The diluting agent may comprise a mixture of non-polar hydrocarbons, the non-polar hydrocarbons being C2-C30 alkanes, the mixture being substantially aliphatic and substantially non-halogenated. The diluting agent may comprise at least 50 wt. % of a mixture of non-polar hydrocarbons, the non-polar hydrocarbons being C2-C30 alkanes, the mixture being substantially aliphatic and substantially non-halogenated. "Substantially aliphatic and substantially non-halogenated" means less than 10% by weight of aromaticity and with no more than 1 mole percent halogen atoms. The level of aromaticity may be less than 5, less than 3, less than 1, or 0 % by weight. The diluting agent may comprise a mixture of non-polar hydrocarbons and may be a gas plant condensate comprising at least one C3-C17 n-alkane, at least one C5-C7 cycloalkane, and at least one C6-C8 aromatic hydrocarbon. The diluting agent may be present in an amount of 75-98 vol. % or 87-96 vol. % in the composition at STP.

[0077] The diluting agent may be a fluid of a lower viscosity and lower density than those of the viscous oil being recovered. Its viscosity may, for example, be 0.2 to 5 cP (centipoise) at room temperature and at a pressure high enough to make it liquid. Its density may be, for example, 450 to 750 kg/m³ at 15°C and at a pressure high enough to make it liquid. The mixture or the blend of diluting agent and viscous oil may have a viscosity and a density that is in between those of the diluting agent and the viscous oil. The diluting agent may or may not precipitate asphaltenes if its concentration exceeds a critical concentration. The diluting agent may be injected as a liquid, as a heated liquid, as a vapor, as a mixture of vapour and liquid, as a supercritical fluid, or as a combination thereof.

[0078] The steam may have a quality (defined as the wt. % of total steam present as steam vapour, and the remainder as liquid) of at least 5%, or 10-95%. The steam may be present in an amount of 2-25 vol. %, or 4-8 vol. % in the composition at STP. The inclusion of

steam may increase the latent heat of the mobilizing composition, which upon condensation transfers more heat than the diluting agent alone to cooler bitumen, raising its temperature and reducing its viscosity. For instance, as illustrated in the simulations described below, inclusion of only 5 vol. % steam in a steam-C7 mixture increases the mixture's latent heat by 58% and the total heat by 55% over C7 alone at 201°C (C7 refers to heptane). A higher latent heat may reduce the viscosity of bitumen, which may allow more penetration of diluting agent into the oil sands matrix, as explained below. The result may be a larger swept volume and/or a higher bitumen recovery.

[0079] The steam may be added continuously with the diluting agent or may be added intermittently or cyclically with the diluting agent. The steam injection rate in each injection period can be the same during intermittent injection or different in different injection periods. The injection periods can be the same or variable. Steam rate in intermittent injection may be higher than the continuous injection case. The cumulative steam in the intermittent steam injection case may be the same as the cumulative steam injection in the continuous steam injection case. For example, the steam injection rate can be $x \text{ m}^3/\text{D}$ (meters³ per day) for the continuous case and $2x \text{ m}^3/\text{D}$ in the injection period of two consecutive injection and no-injection periods. The steam injection rate can be tapered or increased with time. The steam injection rate at any time can vary between zero and a non-zero value.

[0080] The accelerating agent may be present, for example, in an amount of 0-5 vol. %, or 0.1 to 5 vol. %, or 0.1 to 1 vol. % in the composition at STP. The accelerating agent may comprise propyl acetate. The accelerating agent may comprise at least 50 wt. % of propyl acetate. The accelerating agent may comprise n-propyl acetate. The accelerating agent may comprise at least 50 wt. % of n-propyl acetate. The accelerating agent may comprise iso-propyl acetate. The accelerating agent may comprise at least 50 wt. % of iso-propyl acetate. The accelerating agent may comprise n-propyl acetate, iso-propyl acetate, or a combination thereof. The accelerating agent may comprise at least 50 wt. % of n-propyl acetate, iso-propyl acetate, or a combination thereof. The accelerating agent may comprise ethyl acetate, methyl acetate, isobutyl acetate, propyl acetate, or a combination thereof. The accelerating agent may comprise at least 50 wt. % of ethyl acetate, methyl acetate, isobutyl acetate, propyl acetate, or a combination thereof. The accelerating agent may have a boiling point within (i.e. above or below) 20°C of the steam. The accelerating agent may have a

boiling point within (i.e. above or below) 20°C of the diluting agent. The accelerating agent may be blended with the diluting agent or the steam.

[0081] In H-VAPEX, a nonpolar diluting agent such as heptane (C7) contacts an oil sands matrix that has a polar water layer around sand grains, and polar-nonpolar bitumen, both in the pore space, thereby making the oil sands matrix polar-nonpolar. The oil sands matrix, being polar-nonpolar, does not welcome the non-polar heptane. The penetration of heptane into the oil sands matrix, therefore, is not very deep. By using a mobilizing composition comprising a polar-nonpolar accelerating agent, the mobilizing composition may be more welcome by the polar-nonpolar oil sands matrix, thereby potentially increasing penetration into the oil sands matrix.

[0082] The mobilizing composition may be injected with other components, such as: diesel, aromatic light catalytic gas oil, or another diluting agent, to provide flow assurance, or CO₂, natural gas, C₃+ hydrocarbons, ketones, or alcohols.

[0083] The mobilizing composition may be used in a gravity drainage process for recovering viscous oil from an underground reservoir. The use may be for injecting the mobilizing composition into a well completed in the underground viscous oil reservoir to mobilize the viscous oil. The use may be intermittent with another mobilizing composition. The another mobilizing composition may comprise the diluting agent.

[0084] While reference is made herein to the use of the mobilizing composition, this is intended to include the use of the mobilizing composition, or its components. That is, the components (i), (ii), and, if present, (iii), need not be formed into a composition and injected as a single composition, but rather they may be injected separately. For instance, the accelerating agent may be added to the steam and this combination may be injected separately from the diluting agent. Additionally, "its components" means in the ranges specified with reference to the composition. That is, while the steam and the diluting agent may be injected separately, they will be added in the relative amounts listed with reference to the composition.

[0085] With reference to Fig. 1, the gravity drainage process for recovering viscous oil from an underground reservoir may comprise (a) injecting the mobilizing composition as described herein into the reservoir to mobilize the viscous oil (102); and (b) producing at least a fraction of the mobilizing composition and the mobilized oil (104).

[0086] The process may further comprise (c) separating and reusing the mobilizing composition. The mobilizing composition may be injected at a temperature of 10-300°C, or 30-300°C, or 80-280°C, or 60-240°C.

[0087] The process may be a gravity drainage process. Gravity drainage processes are those where the mobilizing composition is injected into an upper well and viscous oil drains to a lower well where it is produced. SAGD, SA-SAGD, VAPEX, H-VAPEX (each described in the background section) are all gravity drainage processes but use different mobilizing compositions.

[0088] The gravity drainage process may involve directional drilling to place two horizontal wells in the viscous oil reservoir – a lower well and an upper well positioned above it. The mobilizing composition may be injected into the upper well to dilute and reduce the viscosity of the viscous oil. The viscous oil, diluting agent, condensed steam, and accelerating agent (if present) will then drain downward through the reservoir under the action of gravity and flow into the lower production well, whereby these fluids can be pumped to the surface. At the surface of the well, reduced-viscosity hydrocarbons may be separated from the produced fluids. The reduced-viscosity hydrocarbons may then be diluted with appropriate light hydrocarbons for transport to a refinery or an upgrader. At the surface of the well, the mobilizing composition may be separated from the produced fluids, purified, and recycled into the process.

[0089] Light hydrocarbon gases may also be separated from the produced fluids and may include hydrocarbons and/or carbon compounds with four or fewer carbon atoms, such as methane, ethane, propane, and/or butane. Light hydrocarbon gases may be used upstream in the process, for instance, as fuel to heat the mobilizing composition prior to injection.

[0090] The mobilizing composition may be injected at an injection temperature. The mobilizing composition may be selected such that its saturated vapor pressure at the injection temperature is less than a threshold maximum pressure of the subterranean formation. This may prevent damage to the subterranean formation and/or escape of the mobilizing composition from the subterranean formation. Threshold maximum pressures may include, for example, a characteristic pressure of the subterranean formation, such as a fracture pressure of the subterranean formation, a hydrostatic pressure within the subterranean formation, a lithostatic pressure within the subterranean formation, a gas cap

pressure for a gas cap that is present within the subterranean formation, and/or an aquifer pressure for an aquifer that is located above and/or under the subterranean formation. The above-mentioned pressures may be measured and/or determined in any suitable manner. For example, this may include measuring a selected pressure with a downhole pressure sensor, calculating the pressure from any suitable property and/or characteristic of the subterranean formation, and/or estimating the pressure, such as via modeling the subterranean formation. The threshold pressures disclosed herein may be selected to correspond to any suitable or desired manner to one or more of these measured or calculated pressures. For example, the threshold pressures disclosed herein may be selected to be greater than, to be less than, to be within a selected range of, to be a selected percentage of, or to be within a selected constant of, etc. one or more of these selected or measured pressures. A threshold pressure may be a user-selected, or operator-selected, value that does not directly correspond to a measured or calculated pressure.

[0091] The threshold maximum pressure also may be related to and/or based upon the characteristic pressure of the subterranean formation. This may include threshold maximum pressures that are less than or equal to 95%, less than or equal to 90%, less than or equal to 85%, less than or equal to 80%, less than or equal to 75%, less than or equal to 70%, less than or equal to 65%, less than or equal to 60%, less than or equal to 55%, or less than or equal to 50% of the characteristic pressure for the subterranean formation and/or threshold maximum pressures that are at least 20%, at least 25%, at least 30%, at least 35%, at least 40%, at least 45%, at least 50%, at least 55%, at least 60%, at least 65%, at least 70%, at least 75%, or at least 80% of the characteristic pressure for the subterranean formation. The mobilizing composition may be injected at a pressure of 20% to 95% of a fracture pressure of the reservoir. Suitable ranges may include combinations of any upper and lower amount of characteristic pressure listed above. Additional examples of suitable threshold maximum pressures may include any of the illustrative threshold amounts listed above.

[0092] The mobilizing compositions may have vapor pressures that are greater than a lower threshold pressure of at least 0.2 megapascals (MPa), at least 0.3 MPa, at least 0.4 MPa, at least 0.5 MPa, at least 0.6 MPa, at least 0.7 MPa, at least 0.8 MPa, at least 0.9 MPa, at least 1 MPa, at least 1.1 MPa, at least 1.2 MPa, at least 1.3 MPa, at least 1.4 MPa, at least 1.5 MPa, at least 1.6 MPa, at least 1.7 MPa, at least 1.8 MPa, at least 1.9 MPa, at

least 2 MPa, at least 2.1 MPa, at least 2.2 MPa, at least 2.3 MPa, at least 2.4 MPa, at least 2.5 MPa, at least 2.6 MPa, at least 2.7 MPa, at least 2.8 MPa, at least 2.9 MPa, at least 3.0 MPa, at least 3.1 MPa, at least 3.2 MPa, at least 3.3 MPa, at least 3.4 MPa, and/or 3.5 MPa. Additionally or alternatively, the vapor pressure for the mobilizing composition may be less than an upper threshold pressure that is less than or equal to 4 MPa, less than or equal to 3.9 MPa, less than or equal to 3.8 MPa, less than or equal to 3.7 MPa, less than or equal to 3.6 MPa, less than or equal to 3.5 MPa, less than or equal to 3.4 MPa, less than or equal to 3.3 MPa, less than or equal to 3.2 MPa, less than or equal to 3.1 MPa, less than or equal to 3 MPa, less than or equal to 2.9 MPa, less than or equal to 2.8 MPa, less than or equal to 2.7 MPa, less than or equal to 2.6 MPa, less than or equal to 2.5 MPa, less than or equal to 2.4 MPa, less than or equal to 2.3 MPa, less than or equal to 2.2 MPa, less than or equal to 2.1 MPa, less than or equal to 2.0 MPa, less than or equal to 1.9 MPa, less than or equal to 1.8 MPa, less than or equal to 1.7 MPa, less than or equal to 1.6 MPa, less than or equal to 1.5 MPa, less than or equal to 1.4 MPa, less than or equal to 1.3 MPa, less than or equal to 1.2 MPa, less than or equal to 1.1 MPa, less than or equal to 1 MPa, less than or equal to 0.9 MPa, less than or equal to 0.8 MPa, less than or equal to 0.7 MPa, less than or equal to 0.6 MPa, less than or equal to 0.5 MPa, less than or equal to 0.4 MPa, and/or less than or equal to 0.3 MPa. The mobilizing composition may be injected at a pressure of 0.2 MPa to 4 MPa. Suitable ranges may include combinations of any upper and lower amount of pressure listed above. Additional examples of suitable pressures may include any of the illustrative threshold amounts listed above.

[0093] The injection temperature of the mobilizing composition, when it is injected into the injection well, may be at least 30°C, at least 35°C, at least 40°C, at least 45°C, at least 50°C, at least 55°C, at least 60°C, at least 65°C, at least 70°C, at least 75°C, at least 80°C, at least 85°C, at least 90°C, at least 95°C, at least 100°C, at least 105°C, at least 110°C, at least 115°C, at least 120°C, at least 125°C, at least 130°C, at least 135°C, at least 140°C, at least 145°C, at least 150°C, at least 155°C, at least 160°C, at least 165°C, at least 170°C, at least 175°C, at least 180°C, at least 185°C, at least 190°C, at least 195°C, at least 200°C, at least 205°C, at least 210°C, at least 210°C, at least 220°C, at least 230°C, at least 240°C, and/or at least 250°C. Additionally or alternatively, the injection temperature also may be less than or equal to 300°C, less than or equal to 250°C, less than or equal to 230°C, less than or equal to 220°C, less than or equal to 210°C, less than or equal to 200°C, less than or

equal to 190°C, less than or equal to 180°C, less than or equal to 170°C, less than or equal to 160°C, less than or equal to 150°C, less than or equal to 140°C, less than or equal to 130°C, less than or equal to 120°C, less than or equal to 110°C, less than or equal to 100°C, less than or equal to 90°C, less than or equal to 80°C, less than or equal to 70°C, less than or equal to 60°C, less than or equal to 50°C, and/or less than or equal to 40°C. Suitable ranges may include combinations of any upper and lower amount of stream temperatures listed above. Additional examples of suitable stream temperatures may include any of the illustrative threshold amounts listed above.

[0094] Separation of the produced fluid may be effected in any suitable separation system or structure, such as a single stage separation vessel, a multistage distillation assembly, a liquid-liquid separation or extraction assembly and/or any suitable gas-liquid separation, or extraction assembly.

[0095] Purification of the mobilizing composition may be effected in any suitable system or structure, such as any suitable liquid-liquid separation or extraction assembly, any suitable gas-liquid separation or extraction assembly, any suitable gas-gas separation or extraction assembly, a single stage separation vessel, and/or any suitable multistage distillation assembly.

[0096] Vaporization of the mobilizing composition may be effected by any suitable system or structure above ground or downhole.

[0097] The injection well may be spaced apart from the production well. The production well may extend at least partially below the injection well, may extend at least partially vertically below the injection well, and/or may define a greater distance (or average distance) from the surface when compared to the injection well. At least a portion of the production well may be parallel to, or at least substantially parallel to, a corresponding portion of the injection well. At least a portion of the injection well, and/or of the production well, may include a horizontal, or at least substantially horizontal, portion.

[0098] The process may include preheating or providing thermal energy to at least a portion of the subterranean formation in any suitable manner. The preheating may include electrically preheating the subterranean formation, chemically preheating the subterranean formation, and/or injecting a preheating steam stream into the subterranean formation. The preheating may include preheating any suitable portion of the subterranean formation, such as a portion of the subterranean formation that is proximal to the injection well, a portion of

the subterranean formation that is proximal to the production well, and/or a portion of the subterranean formation that defines a vapor chamber that receives the mobilizing composition.

[0099] Heating the mobilizing composition may include heating the mobilizing composition in any suitable manner, such as directly heating the mobilizing composition in a surface region or using the co-injection with steam.

[00100] Condensing the mobilizing composition within the subterranean formation may include condensing any suitable portion of the mobilizing composition to release a latent heat of condensation of the mobilizing composition, heat the subterranean formation, heat the viscous oil, and/or generate the reduced-viscosity hydrocarbons within the subterranean formation. The condensing may include condensing a majority, at least 50 wt. %, at least 60 wt. %, at least 70 wt. %, at least 80 wt. %, at least 90 wt. %, at least 95 wt. %, at least 99 wt. %, or substantially all of the mobilizing composition within the subterranean formation. The condensing may include regulating a temperature within the subterranean formation to facilitate, or permit, the condensing.

[00101] Producing the reduced-viscosity hydrocarbons may include producing the reduced-viscosity hydrocarbons via any suitable production well, which may extend within the subterranean formation and/or may be spaced apart from the injection well. This may include flowing the reduced-viscosity hydrocarbons from the subterranean formation, through the production well, and to, proximal to, and/or toward the surface region.

[00102] The producing may include producing asphaltenes. The asphaltenes may be present within the subterranean formation and/or within the viscous oil. The asphaltenes may be produced as a portion of the reduced-viscosity hydrocarbons (and/or the reduced-viscosity hydrocarbons may include, or comprise, asphaltenes). The injecting may include injecting into a stimulated region of the subterranean formation that includes asphaltenes, and the producing may include producing at least a threshold fraction of the asphaltenes from the stimulated region. This may include producing at least 10 wt. %, at least 20 wt. %, at least 30 wt. %, at least 40 wt. %, at least 50 wt. %, at least 60 wt. %, at least 70 wt. %, at least 80 wt. %, or at least 90 wt. % of the asphaltenes that are, or were, present within the stimulated region prior to the injecting.

[00103] Recycling the mobilizing composition may include recycling the mobilizing composition in any suitable manner. The recycling may include separating at least a

separated portion of the mobilizing composition from the reduced-viscosity hydrocarbon mixture and/or from the reduced-viscosity hydrocarbons. The recycling also may include utilizing at least a recycled portion of the mobilizing composition as, or as a portion of, the hydrocarbon solvent mixture and/or returning the recycled portion of the condensate to the subterranean formation via the injection well. The recycling may include purifying the recycled portion of the mobilizing composition prior to utilizing the recycled portion of the mobilizing composition and/or prior to returning the recycled portion of the mobilizing composition to the subterranean formation.

[00104] Experimental and Simulation

[00105] Example 1

[00106] This example illustrates the effectiveness of n-propyl acetate ester (n-PAE) over xylene and n-heptane (n-C7) in penetrating an oil sands matrix and recovering more oil.

[00107] Xylene was chosen as a diluting agent for comparison as it is known in the art to be one of the best diluting agents for bitumen extraction as it dissolves all the four bitumen constituents: saturates, aromatics, resins, and asphaltenes. The xylene used is described by Fisher Scientific as being a purified grade and a mixture of ortho, meta, and para isomers and may contain some ethylbenzene. N-heptane was chosen as a diluting agent for comparison as it is considered to be a surrogate for a common diluting agent known as gas plant condensates (GPC), with boiling point, molecular weight, and bitumen viscosity reduction efficiency, each very close to that of GPC. N-PAE was used as the exemplary diluting agent, as it has a boiling point close to that of water, and because of its ready availability, suitability to be tested under ambient conditions, and experimenter-friendly safety considerations (according to the MSDS). While n-PAE is described in this section as a diluting agent, elsewhere in this specification it is used as an accelerating agent, which is combined with another diluting agent.

[00108] The tests were carried out on samples from the Athabasca oil sands from Alberta, Canada. In each test, the amount of the oil sands material and the porosity and permeability of the sand pack were the same. This was ensured by packing 24.83 g of high-grade Athabasca oil sands to a height of 4.5 cm and a volume of 15 mL in a 50 ml graduated cylinder, the bottom part of which was cut off and replaced with a welded screen to allow liquid hydrocarbon drainage to a dish below, while retaining the extracted sands. In each test, 28 mL (5.3 PV (pore volume)) of a test diluting agent was poured on top of the oil

sands and allowed to flow under gravity at atmospheric pressure (101.3 kPa) and room temperature (21°C). The top of the graduated cylinder was covered with a crumpled cleaning paper and the cylinder was placed inside a fume hood.

[00109] The diluting agent penetrated the oil sands in a downward direction and the diluted bitumen dripping out of the bottom screen was collected in a weighed glass or an aluminum dish. The time at which the first drop of diluted bitumen drained out to the dish was recorded as the breakthrough time (BT). After breakthrough, the test was continued until all of the diluting agent penetrated the oil sands and the last drop of diluted bitumen was collected. The time from the start of diluting agent breakthrough to the time the last drop of diluted bitumen collection was recorded as the extraction time (ET). The diluting agent from the diluted bitumen collected in the dish was removed by evaporation and the dish with the diluting agent-free bitumen was weighed, until the weight was constant, to determine the amount of bitumen recovered by each diluting agent. The diluting agent static head caused by diluting agent density differences had negligible impact on BT and ET, as xylene, with the highest density (0.87 g/cm³ at 15 °C) and hence the highest head, had the longest BT and ET. The average penetration rate (Fig. 2) for each diluting agent was determined by dividing the height of the sand pack by the BT and expressing it in terms of ml/D (milliliters per day). The average bitumen production rate (Fig. 3) was calculated by dividing the amount of diluting agent-free bitumen produced by the time of production that included both BT and ET, and expressing it in g/D (grams per day).

[00110] The bench-scale gravity drainage tests under ambient conditions, as described, show that n-PAE has a significantly higher average penetration rate (Fig. 2) and yields a significantly higher average production rate (Fig. 3) than each of the two other tested diluting agents, xylene and n-heptane. The ratio of the average penetration rate by n-PAE to that by n-C7 was 4.7. The ratio of the average bitumen production rate by n-PAE to that by n-C7 was 4.1.

[00111] Using the Butler Mokrys equation (JCPT (*Journal of Canadian Petroleum Technology*), 1991), where N can be assumed to be the diluent penetration rate,

$$N_{\text{Example 1}}/N_{\text{HVAPEX}} = 4.7 \text{ (from lab data).}$$

[00112] The bitumen rate ratio can be estimated as the square root of 4.7, which is 2.2 at breakthrough, which is lower than the average rate ratio of 4.1, measured in the lab. This indicates that lab tests at ambient conditions in a graduated cylinder give lead to higher

bitumen rate than the equation predicts. This discrepancy notwithstanding, the lab tests indicate that under the same conditions, n-PAE is superior to xylene (a very good solvent for bitumen) and n-C7, both in terms of penetrating into oil sands and producing more oil.

[00113] Example 2

[00114] A simulator was used to compare a simulation of a mobilizing composition comprising steam and C7 with that of H-VAPEX using C7. In the simulator, the reservoir model had a grid block size of 1m x 1 m.

[00115] The fluids (steam with C7, and C7) were injected as gases for better energy balance. The production well operated under liquid level control, meaning maintaining a certain liquid level below the production well to reduce vapor or gas production. Injection was at a constant pressure of 1000 KPaa, at a temperature of 201° C, while the fluid injection rates were allowed to vary.

[00116] The following simulations were run:

1. H-VAPEX base case with single diluting agent (C7 as diluting agent, no steam);
2. Mobilizing composition consisting of steam at 0.12, 5, and 7.5 vol. % with C7 as the diluting agent;
3. H-VAPEX base case with mixed diluting agent (50 vol. % C5 and 50 vol. % C7, no steam); and
4. Mobilizing composition consisting of 5 vol. % steam and (47.5 vol. % C5 and 47.5 vol. % C7).

[00117] Fig. 4 shows the uplift in cumulative bitumen as a function of production days by simulation 2 with 5 vol. % steam as compared to simulation 1 (H-VAPEX). An uplift as high as 30% is observed at around 400 days. The uplift then declines, possibly due to lower saturation temperature and production temperature when steam is blended with C7, and the lower temperature reducing the inflow to the well. However, after 1000 days, the uplift starts increasing again. At the end of 2990 days, the cumulative bitumen by simulation 2 with 5 vol. % steam is higher by 22% over simulation 1. Judging from the slope of the uplift increase vs. time, the uplift is expected to be higher than 22% after 2990 days when the simulation was ended.

[00118] Fig. 5 shows that the bitumen rate for simulation 2 with 5 vol. % steam is higher than simulation 1 (H-VAPEX) except between production days of 500 and 1000, the

same period during which cumulative bitumen uplift by simulation 2 declines (Fig. 4), possibly due to the reasons stated above with reference to Fig. 4.

[00119] Fig. 6 shows that the injection rate of C7 is lower in simulation 2 than of simulation 1 (H-VAPEX). To be at constant pressure injection, as was done in both cases, the injected steam in the latter takes up some of the reservoir volume, thereby lowering the C7 rate to keep the pressure same. Lower diluting agent injection rate in simulation 2 means lower cumulative C7 injected.

[00120] Fig. 7 shows a 28% reduction in cumulative C7 injected over 2990 days when comparing simulation 2 with 5 vol. % steam to simulation 1 (H-VAPEX).

[00121] Fig. 8 shows that the cumulative diluting agent recovered (left y-axis) in simulation 1(H-VAPEX) and simulation 2 with 5 vol. % steam is comparable. However, the cumulative diluting agent left in the reservoir (right y-axis) is 30% less for simulation 2, as the injected diluting agent cumulative volume is 28% less.

[00122] Fig. 9 shows an increase of about 1.5 m³ bitumen recovered per m³ diluting agent left in reservoir in simulation 2 with 5 or 7.5 vol. % steam over that in simulation 1 (H-VAPEX).

[00123] Fig. 10 shows that the vapor chamber of simulation 2 with 5 vol. % steam is fuller and has reached farther into reservoir than that of simulation 1 at 2990 days.

[00124] Fig. 11 shows that the some part of the reservoir is hotter in simulation 1 (H-VAPEX) than that in simulation 2, because of lower condensation temperature when steam is added to the diluting agent, but overall more area is heated and the heat front has reached farther into the reservoir both horizontally and vertically, in simulation 2 with 5 vol. % steam, as compared to simulation 1 (H-VAPEX).

[00125] Fig. 12 shows that the C7 in simulation 2 with 5 vol. % steam reached further into the reservoir and the C7 chamber is larger than that in simulation 1 (H-VAPEX).

[00126] The following observations are made from the simulations, all at 2990 days.

[00127] The 95 vol.% C7 and 5 vol.% steam simulation 2 shows improvement over the C7 H-VAPEX simulation 1, i.e., as follows:

- A) Higher cumulative bitumen recovery (22% higher) and higher recovery of OBIP (Original Bitumen in Place) (82% vs. 67%);
- B) Lower cumulative injected diluting agent (27% lower);
- C) Less diluting agent left in reservoir (30% less); and

- D) Higher bitumen recovery per diluting agent left in the reservoir (m^3/m^3) (3.84 vs. 2.20).

[00128] The 5 vol. % steam and 47.5 vol. % C5 and 47.5 vol.% C7 simulation 4 shows improvement over the 50 vol. % C5 and 50 vol.% C7 simulation 3., i.e., as follows:

- A) Higher cumulative bitumen recovery (7.5% higher) and higher recovery of OBIP (Original Bitumen in Place) (61.4% vs. 57.1%);
- B) Lower cumulative injected diluting agent (27% lower);
- C) Less diluting agent left in reservoir (26.5% less); and
- D) Higher bitumen recovery per diluting agent left in the reservoir (m^3/m^3) (4.4 vs. 3.0).

START-UP COMPOSITION

[00129] As used herein, "start-up", when used with processes such as VAPEX, H-VAPEX, SAGD, SA-SAGD, and steam flood, generally means the phase which ends when fluid communication is established between the first and second wells. Fluid communication may be indicated by injection pressure, pressure differential between injector and producer, injection rate, production rate, or oil content in the produced fluids. "Start-up", when used with CSDRP, generally means the phase which ends when a near wellbore region is substantially depleted of viscous oil. Substantial depletion in the near wellbore region may be indicated by injection pressure, pressure differential between injector and producer, injection rate, production rate, or oil content in the produced fluids.

[00130] Described herein is start-up composition for use in a start-up phase of a process for recovering viscous oil from an underground reservoir. The start-up composition comprises (i) 74.9-97.9 vol. % diluting agent; (ii) 2-25 vol. % steam having a steam quality of at least 5%; and (iii) 0.1-5 vol. % accelerating agent for accelerating penetration of the diluting agent into the viscous oil. The vol. % in each item is at standard temperature and pressure (STP).

[00131] The diluting agent may comprise a non-polar hydrocarbon with 2 to 30 carbon atoms. The diluting agent may comprise at least 50 wt. % of a non-polar hydrocarbon with 2 to 30 carbon atoms. The diluting agent may comprise a C2-C30 alkane. The diluting agent may comprise at least 50 wt. % of a C2-C30 alkane. The diluting agent may comprise a C2-C30 n-alkane. The diluting agent may comprise at least 50 wt. % of a C2-C30 n-alkane. The diluting agent may comprise a C2-C20 alkane. The diluting agent may comprise at least

50 wt. % of a C2-C20 alkane. The diluting agent may comprise a C2-C20 n-alkane. The diluting agent may comprise a C2-C20 n-alkane. The diluting agent may comprise a C2-C5 alkane. The diluting agent may comprise at least 50 wt. % of a C2-C5 alkane. The diluting agent may comprise propane. The diluting agent may comprise at least 50 wt. % of propane. The diluting agent may comprise a C5-C7 cycloalkane. The diluting agent may comprise at least 50 wt. % of a C5-C7 cycloalkane. The diluting agent may comprise cyclohexane. The diluting agent may comprise at least 50 wt. % cyclohexane. The diluting agent may comprise a mixture of non-polar hydrocarbons, the non-polar hydrocarbons being C2-C30 alkanes, the mixture being substantially aliphatic and substantially non-halogenated. The diluting agent may comprise at least 50 wt. % of a mixture of non-polar hydrocarbons, the non-polar hydrocarbons being C2-C30 alkanes, the mixture being substantially aliphatic and substantially non-halogenated. "Substantially aliphatic and substantially non-halogenated" means less than 10% by weight of aromaticity and with no more than 1 mole percent halogen atoms. The level of aromaticity may be less than 5, less than 3, less than 1, or 0 % by weight. The diluting agent may comprise a mixture of non-polar hydrocarbons and may be a gas plant condensate comprising at least one C3-C17 n-alkane, at least one C5-C7 cycloalkane, and at least one C6-C8 aromatic hydrocarbon. The diluting agent may comprise at least 50 wt. % of a mixture of non-polar hydrocarbons and may be a gas plant condensate comprising at least one C3-C17 n-alkane, at least one C5-C7 cycloalkane, and at least one C6-C8 aromatic hydrocarbon. The diluting agent may be present in an amount of 74.9-97.9 vol. % or 87-96 vol. % in the composition at STP.

[00132] The diluting agent may be a fluid of a lower viscosity and lower density than those of the viscous oil being recovered. Its viscosity may, for example, be 0.2 to 5 cP (centipoise) at room temperature and at a pressure high enough to make it liquid. Its density may be, for example, 450 to 750 kg/m³ at 15°C and at a pressure high enough to make it liquid. The mixture or the blend of diluting agent and viscous oil may have a viscosity and a density that is in between those of the diluting agent and the viscous oil. The diluting agent may or may not precipitate asphaltenes if its concentration exceeds a critical concentration. The diluting agent may be injected as a liquid, as a heated liquid, as a vapour, as a mixture of vapour and liquid, as a supercritical fluid, or as a combination thereof.

[00133] The steam may have a quality (defined as the wt. % of total steam present as steam vapour, and the remainder as liquid) of at least 5%, or 10-95%. The steam may be

present in an amount of 2-25 vol. %, or 4-8 vol. % in the composition at STP. The inclusion of steam may increase the latent heat of the start-up composition, which upon condensation transfers more heat than the diluting agent alone to cooler bitumen, raising its temperature and reducing its viscosity. A higher latent heat may reduce the viscosity of bitumen, which may allow more penetration of diluting agent into the oil sands matrix.

[00134] The steam may be added continuously with the diluting agent or may be added intermittently or cyclically with the diluting agent. The steam injection rate in each injection period can be the same during intermittent injection or different in different injection periods. The injection periods can be the same or variable. Steam rate in intermittent injection may be higher than the continuous injection case. The cumulative steam in the intermittent steam injection case may be the same as the cumulative steam injection in the continuous steam injection case. For example, the steam injection rate can be $x \text{ m}^3/\text{D}$ (meters³ per day) for the continuous case and $2x \text{ m}^3/\text{D}$ in the injection period of two consecutive injection and no-injection periods. The steam injection rate can be tapered or increased with time. The steam injection rate at any time can vary between zero and a non-zero value.

[00135] The accelerating agent may be present in an amount of 0.1-5 vol. %, or 0.1 to 1 vol. % in the composition at STP. The accelerating agent may comprise an ether with 2 to 8 carbon atoms, or 4 to 8 carbon atoms. The accelerating agent may comprise at least 50 wt. % of an ether with 2 to 8 carbon atoms, or 4 to 8 carbon atoms. The accelerating agent may comprise di-methyl ether, methyl ethyl ether, di-ethyl ether, methyl iso-propyl ether, methyl propyl ether, di-isopropyl ether, di-propyl ether, methyl iso-butyl ether, methyl butyl ether, ethyl iso-butyl ether, ethyl butyl ether, iso-propyl butyl ether, propyl butyl ether, di-isobutyl ether, or di-butyl ether. The accelerating agent may comprise at least 50 wt. % of di-methyl ether, methyl ethyl ether, di-ethyl ether, methyl iso-propyl ether, methyl propyl ether, di-isopropyl ether, di-propyl ether, methyl iso-butyl ether, methyl butyl ether, ethyl iso-butyl ether, ethyl butyl ether, iso-propyl butyl ether, propyl butyl ether, di-isobutyl ether, or di-butyl ether. The accelerating agent may comprise di-methyl ether. The accelerating agent may comprise at least 50 wt. % of di-methyl ether. The accelerating agent may comprise di-ethyl ether. The accelerating agent may comprise at least 50 wt. % of di-ethyl ether. The accelerating agent may comprise propyl acetate. The accelerating agent may comprise at least 50 wt. % of propyl acetate. The accelerating agent may comprise n-propyl acetate. The

accelerating agent may comprise at least 50 wt. % of n-propyl acetate. The accelerating agent may comprise iso-propyl acetate. The accelerating agent may comprise at least 50 wt. % of iso-propyl acetate. The accelerating agent may comprise n-propyl acetate, iso-propyl acetate, or a combination thereof. The accelerating agent may comprise at least 50 wt. % of n-propyl acetate, iso-propyl acetate, or a combination thereof. The accelerating agent may comprise ethyl acetate, methyl acetate, isobutyl acetate, propyl acetate, or a combination thereof. The accelerating agent may comprise at least 50 wt. % of ethyl acetate, methyl acetate, isobutyl acetate, propyl acetate, or a combination thereof. The accelerating agent may have a boiling point within (i.e. above or below) 20°C of the steam at reservoir pressure. The accelerating agent may have a boiling point within (i.e. above or below) 20°C of the diluting agent at reservoir pressure. The accelerating agent may be blended with the diluting agent or the steam.

[00136] The start-up composition may be injected with other components, such as: diesel, viscous oil, bitumen, or another diluting agent, to provide flow assurance, or CO₂, natural gas, C₃₊ hydrocarbons, ketones, or alcohols.

[00137] The start-up composition may be used in a process for recovering viscous oil from an underground reservoir. The process for recovering viscous oil may be SAGD, SA-SAGD, CSDRP (e.g. CSP™), LASER, VAPEX, or H-VAPEX (e.g. N-Solv®), or a steam flood process.

[00138] While reference is made to the use of the start-up composition, this is intended to include the use of the start-up composition, or its components. That is, the components (i), (ii), (iii) need not be formed into a composition and injected as a single composition, but rather they may be injected separately. For instance, the accelerating agent may be added to the steam and this combination may be injected separately from the diluting agent. Additionally, "its components" means in the ranges specified with reference to the composition. That is, while the steam and the diluting agent may be injected separately, they will be added in the relative amounts listed with reference to the composition.

[00139] With reference to Fig. 13, a start-up phase of a process for recovering viscous oil from an underground reservoir may comprise providing a start-up composition as described herein (1302), and injecting the start-up composition, or its components, into the underground reservoir (1304).

[00140] The start-up composition may be injected at a temperature of 10-300°C, or 30-300°C, or 80-280°C, or 60-240°C. The start-up composition may be heated in any suitable manner, such as directly heating the start-up composition in a surface region or using co-injection with steam. The start-up composition may be preheated to heated liquid, saturated liquid, saturated vapour, a mixture of saturated liquid and vapour, or superheated vapour on the surface. Steam may be added separately from a steam line to the diluting agent, or steam may be made in one vessel to which both water and diluting agent are injected and heated to give a vapour mixture consisting of vapour diluent and steam in a predetermined ratio. The accelerating agent may then be added to the vapour mixture. Vaporization of the start-up composition may be effected by any suitable system or structure above ground or downhole.

[00141] The start-up phase may further comprise, prior to injecting the start-up composition, heating wellbores of the wells by steam circulation. The process may include preheating or providing thermal energy to at least a portion of the subterranean formation in any suitable manner. The preheating may include electrically preheating the subterranean formation, chemically preheating the subterranean formation, and/or injecting a preheating steam stream into the subterranean formation. The preheating may include preheating any suitable portion of the subterranean formation, such as a portion of the subterranean formation that is proximal to the injection well, a portion of the subterranean formation that is proximal to the production well, and/or a portion of the subterranean formation that defines a vapour chamber that receives the mobilizing composition.

[00142] The composition and/or temperature of the start-up composition may vary over the course of the start-up phase. For instance, near the start of the start-up phase, the composition may be toward the lower end of the range of 74.9-97.9 vol. % diluting agent; the higher end of the range of 2-25 vol. % steam having a steam quality of at least 5%; and the higher end of the range 0.1-5 vol. % of the accelerating agent, in order to make the composition more polar and hence more easily injected into the oil sands. Near the end of the start-up phase, only steam or diluting agent may be injected into one well and the mobilized fluids recovered from the other well so as to recover the accelerating agent. For a steam-based recovery process, steam may be injected near the end of the start-up phase. For a diluent-dominated process, diluent may be injected at the end of the start-up phase. Furthermore, for a steam-based recovery process, steam may be injected near the end of

the start-up phase, but only to the injector of the injector-producer well pair. Similarly, for a diluent-dominated process, diluent may be injected at the end of the start-up phase, but only to the injector of the injector-producer well pair. The temperature of the composition may be higher than recovery process temperature near the start of the start-up phase and then tapered to recovery process temperature near the end of the start-up phase.

[00143] Where the start-up phase is used in VAPEX or H-VAPEX (e.g. N-Solv®), the start-up phase may comprise:

- a) providing a start-up composition as described herein;
- b) individually cyclically injecting and producing the start-up composition into the reservoir via a first well and a second well of a well pair, wherein the first and second wells are each individually an injector or producer well of the well pair;
- c) flooding from the first well to the second well by injecting the start-up composition into the first well and producing from the second well;
- d) flooding from the second well to the first well by injecting the start-up composition into the second well and producing from the first well; and
- e) repeating steps c) and d) until fluid communication is established between the first and second wells. Fluid communication may be indicated by injection pressure, pressure differential between injector and producer, injection rate, production rate, or oil content in the produced fluids.

[00144] Where the start-up phase is used in SAGD or SA-SAGD, the start-up phase may comprise:

- a) providing the start-up composition as described herein;
- b) individually cyclically injecting and producing the start-up composition into the reservoir via a first well and a second well of a well pair, wherein the first and second wells are each individually an injector or producer well of the well pair;
- c) flooding from the first well to the second well by injecting the start-up composition into the first well and producing from the second well;
- d) flooding from the second well to the first well by injecting the start-up composition into the second well and producing from the first well; and
- e) repeating steps c) and d) until fluid communication is established between the first and second wells. Fluid communication may be indicated by injection

pressure, pressure differential between injector and producer, injection rate, production rate, or oil content in the produced fluids.

[00145] Where the start-up phase is used in CSDRP (e.g. CSPTM), the start-up phase may comprise:

- a) providing the start-up composition as described herein; and
- b) individually cyclically injecting and producing the start-up composition into the reservoir via at least one well disposed in the reservoir until a near wellbore region is substantially depleted of viscous oil. Substantial depletion in the near wellbore region may be indicated by injection pressure, pressure differential between injector and producer, injection rate, production rate, or oil content in the produced fluids.

[00146] Where the start-up phase is used in a steam flood, the start-up phase may comprise:

- a) providing the start-up composition as described herein;
- b) individually cyclically injecting and producing the start-up composition into the reservoir via a first well and a second well of a well pair, wherein the first and second wells are each individually an injector or producer well of the well pair;
- c) flooding from the first well to the second well by injecting the start-up composition into the first well and producing from the second well;
- d) flooding from the second well to the first well by injecting the start-up composition into the second well and producing from the first well; and
- e) repeating steps c) and d) until fluid communication is established between the first and second wells. Fluid communication may be indicated by injection pressure, pressure differential between injector and producer, injection rate, production rate, or oil content in the produced fluids.

[00147] The start-up composition may be injected at a pressure which is less than a threshold maximum pressure of the subterranean formation. This may prevent damage to the subterranean formation and/or escape of the mobilizing composition from the subterranean formation. Threshold maximum pressures may include, for example, a characteristic pressure of the subterranean formation, such as a fracture pressure of the subterranean formation, a hydrostatic pressure within the subterranean formation, a lithostatic pressure within the subterranean formation, a gas cap pressure for a gas cap that is present within the

subterranean formation, and/or an aquifer pressure for an aquifer that is located above and/or under the subterranean formation. The above-mentioned pressures may be measured and/or determined in any suitable manner. For example, this may include measuring a selected pressure with a downhole pressure sensor, calculating the pressure from any suitable property and/or characteristic of the subterranean formation, and/or estimating the pressure, such as via modeling the subterranean formation. The threshold pressures disclosed herein may be selected to correspond to any suitable or desired manner to one or more of these measured or calculated pressures. For example, the threshold pressures disclosed herein may be selected to be greater than, to be less than, to be within a selected range of, to be a selected percentage of, or to be within a selected constant of, etc. one or more of these selected or measured pressures. A threshold pressure may be a user-selected, or operator-selected, value that does not directly correspond to a measured or calculated pressure.

[00148] The threshold maximum pressure also may be related to and/or based upon the characteristic pressure of the subterranean formation. This may include threshold maximum pressures that are less than or equal to 95%, less than or equal to 90%, less than or equal to 85%, less than or equal to 80%, less than or equal to 75%, less than or equal to 70%, less than or equal to 65%, less than or equal to 60%, less than or equal to 55%, or less than or equal to 50% of the characteristic pressure for the subterranean formation and/or threshold maximum pressures that are at least 20%, at least 25%, at least 30%, at least 35%, at least 40%, at least 45%, at least 50%, at least 55%, at least 60%, at least 65%, at least 70%, at least 75%, or at least 80% of the characteristic pressure for the subterranean formation. Suitable ranges may include combinations of any upper and lower amount of characteristic pressure listed above. Additional examples of suitable threshold maximum pressures may include any of the illustrative threshold amounts listed above.

[00149] The start-up compositions may be injected at pressures that are greater than a lower threshold pressure of at least 0.2 megapascals (MPa), at least 0.3 MPa, at least 0.4 MPa, at least 0.5 MPa, at least 0.6 MPa, at least 0.7 MPa, at least 0.8 MPa, at least 0.9 MPa, at least 1 MPa, at least 1.1 MPa, at least 1.2 MPa, at least 1.3 MPa, at least 1.4 MPa, at least 1.5 MPa, at least 1.6 MPa, at least 1.7 MPa, at least 1.8 MPa, at least 1.9 MPa, at least 2 MPa, at least 2.1 MPa, at least 2.2 MPa, at least 2.3 MPa, at least 2.4 MPa, and/or at least 2.5 MPa. Additionally or alternatively, the pressure for the start-up composition may be

less than an upper threshold pressure that is less than or equal to 10 MPa, less than or equal to 9 MPa, less than or equal to 8 MPa, less than or equal to 7 MPa, less than or equal to 6 MPa, less than or equal to 5 MPa, less than or equal to 4 MPa, less than or equal to 3 MPa, less than or equal to 2.5 MPa, less than or equal to 2.3 MPa, less than or equal to 2.0 MPa, less than or equal to 1.9 MPa, less than or equal to 1.8 MPa, less than or equal to 1.7 MPa, less than or equal to 1.6 MPa, less than or equal to 1.5 MPa, less than or equal to 1.4 MPa, less than or equal to 1.3 MPa, less than or equal to 1.2 MPa, less than or equal to 1.1 MPa, less than or equal to 1 MPa, less than or equal to 0.9 MPa, less than or equal to 0.8 MPa, less than or equal to 0.7 MPa, less than or equal to 0.6 MPa, less than or equal to 0.5 MPa, less than or equal to 0.4 MPa, and/or less than or equal to 0.3 MPa. Suitable ranges may include combinations of any upper and lower amount of pressure listed above. Additional examples of suitable pressures may include any of the illustrative threshold amounts listed above.

[00150] The injection temperature of the start-up composition, when it is injected into the injection well, may be at least 30°C, at least 35°C, at least 40°C, at least 45°C, at least 50°C, at least 55°C, at least 60°C, at least 65°C, at least 70°C, at least 75°C, at least 80°C, at least 85°C, at least 90°C, at least 95°C, at least 100°C, at least 105°C, at least 110°C, at least 115°C, at least 120°C, at least 125°C, at least 130°C, at least 135°C, at least 140°C, at least 145°C, at least 150°C, at least 155°C, at least 160°C, at least 165°C, at least 170°C, at least 175°C, at least 180°C, at least 185°C, at least 190°C, at least 195°C, at least 200°C, at least 205°C, and/or at least 210°C. Additionally or alternatively, the injection temperature also may be less than or equal to 300°C, less than or equal to 250°C, less than or equal to 230°C, less than or equal to 220°C, less than or equal to 210°C, less than or equal to 200°C, less than or equal to 190°C, less than or equal to 180°C, less than or equal to 170°C, less than or equal to 160°C, less than or equal to 150°C, less than or equal to 140°C, less than or equal to 130°C, less than or equal to 120°C, less than or equal to 110°C, less than or equal to 100°C, less than or equal to 90°C, less than or equal to 80°C, less than or equal to 70°C, less than or equal to 60°C, less than or equal to 50°C, and/or less than or equal to 40°C. Suitable ranges may include combinations of any upper and lower amount of stream temperatures listed above. Additional examples of suitable stream temperatures may include any of the illustrative threshold amounts listed above.

[00151] Separation of produced fluids from the underground reservoir may be effected in any suitable separation system or structure, such as a single stage separation vessel, a multistage distillation assembly, a liquid-liquid separation or extraction assembly and/or any suitable gas-liquid separation, or extraction assembly. The produced fluids from the start-up phase may be processed with the recovery phase produced fluids.

[00152] Purification of the start-up composition may be effected in any suitable system or structure, such as any suitable liquid-liquid separation or extraction assembly, any suitable gas-liquid separation or extraction assembly, any suitable gas-gas separation or extraction assembly, a single stage separation vessel, and/or any suitable multistage distillation assembly.

[00153] In gravity drainage processes, the injection well may be spaced apart from the production well. The production well may extend at least partially below the injection well, may extend at least partially vertically below the injection well, and/or may define a greater distance (or average distance) from the surface when compared to the injection well. At least a portion of the production well may be parallel to, or at least substantially parallel to, a corresponding portion of the injection well. At least a portion of the injection well, and/or of the production well, may include a horizontal, or at least substantially horizontal, portion.

[00154] Condensing the start-up composition within the subterranean formation may include condensing any suitable portion of the start-up composition to release a latent heat of condensation of the start-up composition, heat the subterranean formation, heat the viscous oil, and/or generate the reduced-viscosity hydrocarbons within the subterranean formation. The condensing may include condensing a majority, at least 50 wt. %, at least 60 wt. %, at least 70 wt. %, at least 80 wt. %, at least 90 wt. %, at least 95 wt. %, at least 99 wt. %, or substantially all of the start-up composition within the subterranean formation. The condensing may include regulating a temperature within the subterranean formation to facilitate, or permit, the condensing.

[00155] Recycling the start-up composition may include recycling the start-up composition in any suitable manner. The recycling may include separating at least a separated portion of the start-up composition from the reduced-viscosity hydrocarbon mixture and/or from the reduced-viscosity hydrocarbons. The recycling also may include utilizing at least a recycled portion of the start-up composition as, or as a portion of, the hydrocarbon solvent mixture and/or returning the recycled portion of the condensate to the subterranean

formation via the injection well. The recycling may include purifying the recycled portion of the start-up composition prior to utilizing the recycled portion of the start-up composition and/or prior to returning the recycled portion of the start-up composition to the subterranean formation. Recycling may also include returning the recycled portion of the condensate to the subterranean formation via another injection well requiring start-up.

[00156] Experimental and Simulation

[00157] Example 1

[00158] This example illustrates the effectiveness of n-propyl acetate ester (PAE) in increasing the average penetration rate into oil sands and the average bitumen production rate over xylene and n-heptane (C7).

[00159] Xylene was chosen as a diluent for comparison as it was previously considered to be one of the best diluents for bitumen extraction, because of its known ability to dissolve all the four bitumen constituents, namely saturates, aromatics, resin and asphaltenes. The xylene used is described by Fisher Scientific as being a purified grade and a mixture of ortho, meta, and para isomers and may contain some ethylbenzene. N-heptane was chosen as a diluent for comparison as it may be considered to be a surrogate for a common diluent known as gas plant condensates (GPC), because its boiling point, molecular weight, and bitumen viscosity reduction efficiency are close to those of GPC.

[00160] PAE was used as the exemplary multi-purpose agent because it has a boiling point close to that of water, and because of its ready availability, suitability to be tested under ambient conditions, and experimenter-friendly safety considerations (according to the MSDS data sheets).

[00161] The tests were carried out on samples from the Athabasca oil sands from Alberta, Canada. In each test, the amount of the oil sands material and the porosity and permeability of the sand pack were the same. This was ensured by packing 24.83 g of high-grade Athabasca oil sands to a height of 4.5 cm and a volume of 15 mL in a 50 mL graduated cylinder, the bottom part of which was cut off and replaced with a welded screen to allow liquid hydrocarbon drainage, while retaining the extracted sands. In each test, 28 mL (5.3 PV (pore volume)) of a test diluent was poured on top of the oil sands and allowed to flow under gravity at atmospheric pressure (101.3 kPa) and room temperature (21°C). The top of the graduated cylinder was covered with a crumpled cleaning paper and the cylinder was placed inside a fume hood.

[00162] The diluent penetrated the oil sands in a downward direction and the diluted bitumen dripping out of the bottom screen was collected in a weighed glass or an aluminum dish. The time at which the first drop of diluted bitumen drained out to the dish was recorded as the breakthrough time (BT). After breakthrough, the test was continued until all the diluent penetrated the oil sands and the last drop of diluted bitumen was collected. The time from the start of diluent breakthrough to the time the last drop of diluted bitumen collection was recorded and termed as the extraction time (ET). The diluent from the diluted bitumen collected in the dish was removed by evaporation and the dish with the diluent-free bitumen was weighed to determine the amount of bitumen recovered by each diluent. The diluent static head caused by diluent density differences had negligible impact on BT and ET, as xylene, with the highest density (0.87 g/cm^3 at 15°C) and hence the highest head, had the longest BT and ET. The average penetration rate (Fig. 14) for each diluent was determined by dividing the height of the sand pack by the BT and expressing it in terms of mID. The average bitumen production rate (Fig. 15) was calculated by dividing the amount of diluent-free bitumen produced by the time of production that included both BT and ET, and expressing it in gID.

[00163] The bench-scale gravity drainage tests under ambient conditions using n-PAE as the multi-purpose agent show that the multi-purpose agent has a significantly higher (by a factor of 4.7 over C7) average penetration rate (Fig. 14) and yields a significantly higher average production rate (Fig. 15) than each of the two prior art diluents: xylene and n-heptane. The ratio of the average bitumen production rate by PAE to that by C7 is 4.1.

[00164] Using the Butler Mokrys equation (JCPT (*Journal of Canadian Petroleum Technology*), 1991), where N can be assumed to be the diluent penetration rate.

[00165] $N_{\text{Example 1}}/N_{\text{H-VAPEX}} = 4.7$ (from lab data).

[00166] The bitumen rate ratio can be estimated as the square root of 4.7, which is 2.2 at breakthrough, which is lower than the average rate ratio of 4.1, measured in the lab. This indicates that lab tests at ambient conditions in a graduated cylinder give lead to higher bitumen rate than the equation predicts. This discrepancy notwithstanding, the lab tests indicate that under the same conditions, n-PAE is superior to xylene (a very good solvent for bitumen) and n-C7, both in terms of penetrating into oil sands and producing more oil.

[00167] A simulator was used to compare a simulation of a composition comprising steam and C7 with that of H-VAPEX using C7. In the simulator, the reservoir model had a

gird block size of 1m x 1 m. Injection was at a constant pressure of 1 MPa and a temperature of 201° C, while the fluid injection rates were allowed to vary.

[00168] The following simulations were run:

[00169] 1. H-VAPEX base case with C7 only (no steam)

[00170] 2. H-VAPEX with C7 plus 5 vol. % steam

[00171] For the first 90 days, the wellbores were heated without fluid injection. Then, in each simulation, injection was at 201° C and 1 MPa.

[00172] The vapour chamber after 150 days was larger in simulation 2 than in simulation 1, as seen in Fig. 16.

[00173] After 190 days (Fig. 17), the vapour chamber of simulation 2 was again larger than in simulation 1, showing less gravity override and more lateral growth, which means the sweep efficiency of simulation 2 was higher than that in simulation 1.

[00174] Fig. 18 illustrates the % increase in cumulative bitumen in simulation 2 over simulation 1. Fig. 18 illustrates that simulation 2 has a faster start-up and a 25 % increase in cumulative bitumen in the next 110 days over simulation 1.

[00175] It should be understood that numerous changes, modifications, and alternatives to the preceding disclosure can be made without departing from the scope of the disclosure. The preceding description, therefore, is not meant to limit the scope of the disclosure. Rather, the scope of the disclosure is to be determined only by the appended claims and their equivalents. It is also contemplated that structures and features in the present examples can be altered, rearranged, substituted, deleted, duplicated, combined, or added to each other.

CLAIMS:

1. A mobilizing composition for use in a gravity drainage process for recovering viscous oil from an underground reservoir, the mobilizing composition comprising:
 - (i) 75-98 vol. % diluting agent;
 - (ii) 2-25 vol. % steam having a steam quality of at least 5%; and
 - (iii) 0-5 vol. % accelerating agent for accelerating penetration of the diluting agent into the viscous oil.
2. The composition according to claim 1, wherein the composition comprises 0.1 to 1 vol. % of the accelerating agent.
3. The composition according to claim 1 or 2, wherein the diluting agent comprises at least 50 wt. % of at least one non-polar hydrocarbon with 2 to 30 carbon atoms.
4. The composition according to claim 1 or 2, wherein the diluting agent comprises at least 50 wt. % of at least one C2-C30 alkane.
5. The composition according to claim 1 or 2, wherein the diluting agent comprises at least 50 wt. % of at least one C2-C30 n-alkane.
6. The composition according to claim 1 or 2, wherein the diluting agent comprises at least 50 wt. % of at least one C2-C20 alkane.
7. The composition according to claim 1 or 2, wherein the diluting agent comprises at least 50 wt. % of at least one C2-C20 n-alkane.
8. The composition according to claim 1 or 2, wherein the diluting agent comprises at least 50 wt. % of at least one C2-C5 alkane.
9. The composition according to claim 1 or 2, wherein the diluting agent comprises at least 50 wt. % propane.

10. The composition according to claim 1 or 2, wherein the diluting agent comprises at least 50 wt. % of at least one C5-C7 cycloalkane.
11. The composition according to claim 1 or 2, wherein the diluting agent comprises at least 50 wt. % cyclohexane.
12. The composition according to claim 1 or 2, wherein the diluting agent comprises at least 50 wt. % of a mixture of non-polar hydrocarbons, the non-polar hydrocarbons being C2-C30 alkanes, the mixture being substantially aliphatic and substantially non-halogenated.
13. The composition according to claim 1 or 2, wherein the diluting agent comprises at least 50 wt. % of a mixture of non-polar hydrocarbons and is a gas plant condensate comprising at least one C3-C17 n-alkane, at least one C5-C7 cycloalkane, and at least one C6-C8 aromatic hydrocarbon.
14. The composition according to any one of claims 1 to 13, wherein the accelerating agent comprises at least 50 wt. % propyl acetate.
15. The composition according to any one of claims 1 to 13, wherein the accelerating agent comprises at least 50 wt. % n-propyl acetate.
16. The composition according to any one of claims 1 to 13, wherein the accelerating agent comprises at least 50 wt. % iso-propyl acetate.
17. The composition according to any one of claims 1 to 13, wherein the accelerating agent comprises at least 50 wt. % n-propyl acetate, iso-propyl acetate, or a combination thereof.
18. The composition according to any one of claims 1 to 13, wherein the accelerating agent comprises at least 50 wt. % ethyl acetate, methyl acetate, isobutyl acetate, propyl acetate, or a combination thereof.

19. The composition according to any one of claims 1 to 18, wherein the accelerating agent has a boiling point within 20°C of the steam.
20. The composition according to any one of claims 1 to 18, wherein the accelerating agent has a boiling point within 20°C of the diluting agent.
21. The composition according to any one of claims 1 to 13, wherein the steam has a quality of 10-95 %.
22. The composition according to any one of claims 1 to 13, wherein the steam is present in an amount of 4-8 vol. %.
23. The composition according to any one of claims 1 to 13, wherein the diluting agent is present in an amount of 87-96 vol. %.
24. A use of the mobilizing composition according to any one of claims 1 to 23, in the gravity drainage process for recovering the viscous oil from the underground reservoir.
25. The use according to claim 24, wherein the use is for injecting the mobilizing composition into a well completed in the underground viscous oil reservoir to mobilize the viscous oil.
26. The use according to claim 24 or 25, wherein the use is intermittent with injection another mobilizing composition.
27. The use according to 26, wherein another mobilizing composition comprises the diluting agent.
28. A gravity drainage process for recovering viscous oil from an underground reservoir, the process comprising:
 - (a) injecting the mobilizing composition according to any one of claims 1 to 23 into the reservoir to mobilize the viscous oil; and

- (b) producing at least a fraction of the mobilizing composition and the mobilized oil.
29. The process of claim 28, further comprising (c) separating and reusing the mobilizing composition.
30. The process of claim 28, wherein the mobilizing composition is injected at a temperature of 10-300°C.
31. The process of claim 28, wherein the mobilizing composition is injected at a temperature of 30-300°C.
32. The process of claim 28, wherein the mobilizing composition is injected at a temperature of 80-280°C.
33. The process of claim 28, wherein the mobilizing composition is injected at a temperature of 60-240°C.
34. The process of any one of claims 28 to 33, wherein the mobilizing composition is injected at a pressure of 20% to 95% of a fracture pressure of the reservoir.
35. The process of any one of claims 28 to 33, wherein the mobilizing composition is injected at a pressure of 0.2 MPa to 4 MPa.
36. A start-up composition for use in a start-up phase of a process for recovering viscous oil from an underground reservoir, the start-up composition comprising:
- (i) 74.9-97.9 vol. % diluting agent;
 - (ii) 2-25 vol. % steam having a steam quality of at least 5%; and
 - (iii) 0.1-5 vol. % accelerating agent for accelerating penetration of the diluting agent into the viscous oil.
37. The composition according to claim 36, wherein the composition comprises 0.1 to 1 vol. % of the accelerating agent.

38. The composition according to claim 36 or 37, wherein the diluting agent comprises at least 50 wt. % of at least one non-polar hydrocarbon with 2 to 30 carbon atoms.
39. The composition according to claim 36 or 37, wherein the diluting agent comprises at least 50 wt. % of at least one C2-C30 alkane.
40. The composition according to claim 36 or 37, wherein the diluting agent comprises at least 50 wt. % of at least one C2-C30 n-alkane.
41. The composition according to claim 36 or 37, wherein the diluting agent comprises at least 50 wt. % of at least one C2-C20 alkane.
42. The composition according to claim 36 or 37, wherein the diluting agent comprises at least 50 wt. % of at least one C2-C20 n-alkane.
43. The composition according to claim 36 or 37, wherein the diluting agent comprises at least 50 wt. % of at least one C2-C5 alkane.
44. The composition according to claim 36 or 37, wherein the diluting agent comprises at least 50 wt. % propane.
45. The composition according to claim 36 or 37, wherein the diluting agent comprises at least 50 wt. % of at least one C5-C7 cycloalkane.
46. The composition according to claim 36 or 37, wherein the diluting agent comprises at least 50 wt. % cyclohexane.
47. The composition according to claim 36 or 37, wherein the diluting agent comprises at least 50 wt. % of a mixture of non-polar hydrocarbons, the non-polar hydrocarbons being C2-C30 alkanes, the mixture being substantially aliphatic and substantially non-halogenated.

48. The composition according to claim 36 or 37, wherein the diluting agent comprises at least 50 wt. % of a mixture of non-polar hydrocarbons and is a gas plant condensate comprising at least one C3-C17 n-alkane, at least one C5-C7 cycloalkane, and at least one C6-C8 aromatic hydrocarbon.

49. The composition according to any one of claims 36 to 48, wherein the accelerating agent comprises at least 50 wt. % of at least one ether with 2 to 8 carbon atoms.

50. The composition according to any one of claims 36 to 48, wherein the accelerating agent comprises at least 50 wt. % of at least one ether with 4 to 8 carbon atoms.

51. The composition according to any one of claims 36 to 48, wherein the accelerating agent comprises at least 50 wt. % di-methyl ether, methyl ethyl ether, di-ethyl ether, methyl iso-propyl ether, methyl propyl ether, di-isopropyl ether, di-propyl ether, methyl iso-butyl ether, methyl butyl ether, ethyl iso-butyl ether, ethyl butyl ether, iso-propyl butyl ether, propyl butyl ether, di-isobutyl ether, or di-butyl ether.

52. The composition according to any one of claims 36 to 48, wherein the accelerating agent comprises at least 50 wt. % di-methyl ether.

53. The composition according to any one of claims 36 to 48, wherein the accelerating agent comprises at least 50 wt. % di-ethyl ether.

54. The composition according to any one of claims 36 to 48, wherein the accelerating agent comprises at least 50 wt. % propyl acetate.

55. The composition according to any one of claims 36 to 48, wherein the accelerating agent comprises at least 50 wt. % n-propyl acetate.

56. The composition according to any one of claims 36 to 48, wherein the accelerating agent comprises at least 50 wt. % iso-propyl acetate.

57. The composition according to any one of claims 36 to 48, wherein the accelerating agent comprises at least 50 wt. % n-propyl acetate, iso-propyl acetate, or a combination thereof.

58. The composition according to any one of claims 36 to 48, wherein the accelerating agent comprises at least 50 wt. % ethyl acetate, methyl acetate, isobutyl acetate, propyl acetate, or a combination thereof.

59. The composition according to any one of claims 36 to 48, wherein the accelerating agent has a boiling point within 20°C of the steam at reservoir pressure.

60. The composition according to any one of claims 36 to 52, wherein the accelerating agent has a boiling point within 20°C of the diluting agent at reservoir pressure.

61. The composition according to any one of claims 36 to 48, wherein the steam has a quality of 10-95 %.

62. The composition according to any one of claims 36 to 48, wherein the steam is present in an amount of 4-8 vol. %

63. The composition according to any one of claims 36 to 48, wherein the diluting agent is present in an amount of 87-96 vol. %.

64. The composition according to any one of claims 36 to 48, wherein the process for recovering viscous oil is SAGD, SA-SAGD, a CSDRP, LASER, VAPEX, or H-VAPEX, or a steam flood process.

65. A use of the start-up composition according to any one of claims 36 to 63, in the start-up phase of the process for recovering the viscous oil from the underground reservoir.

66. The use according to claim 65, wherein the process for recovering the viscous oil is SAGD, SA-SAGD, CSDRP, LASER, VAPEX, or H-VAPEX, or a steam flood process.

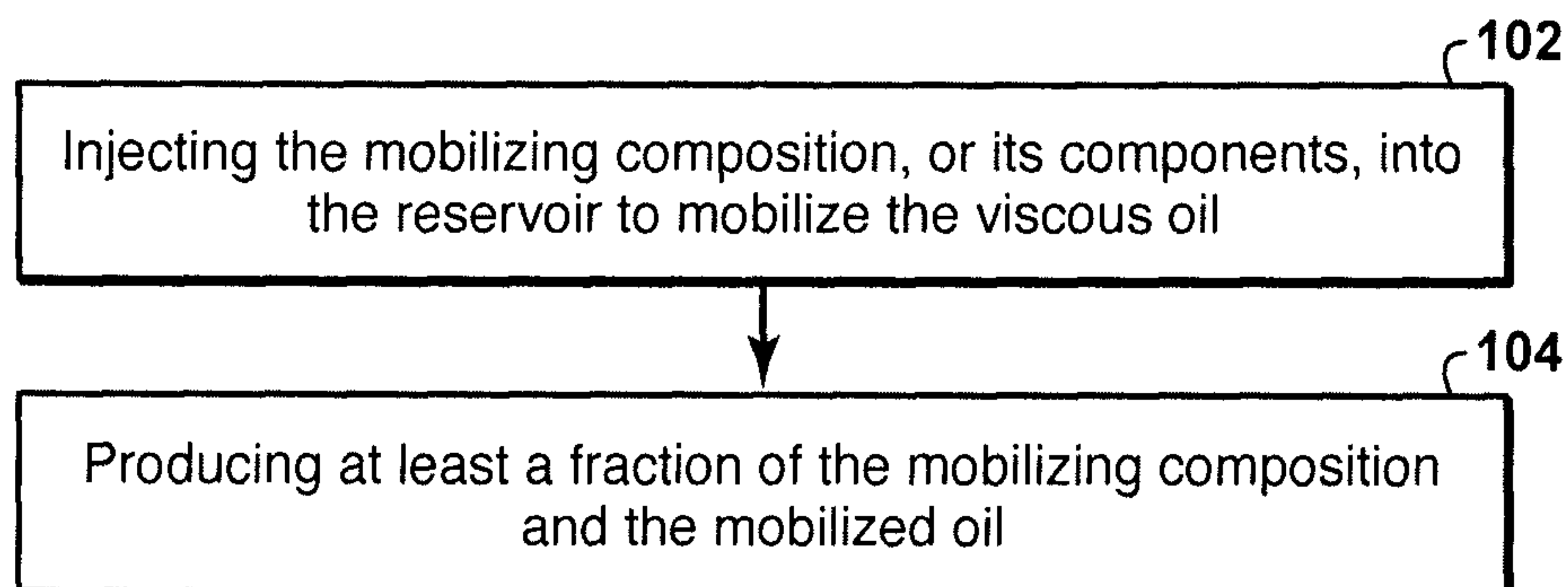
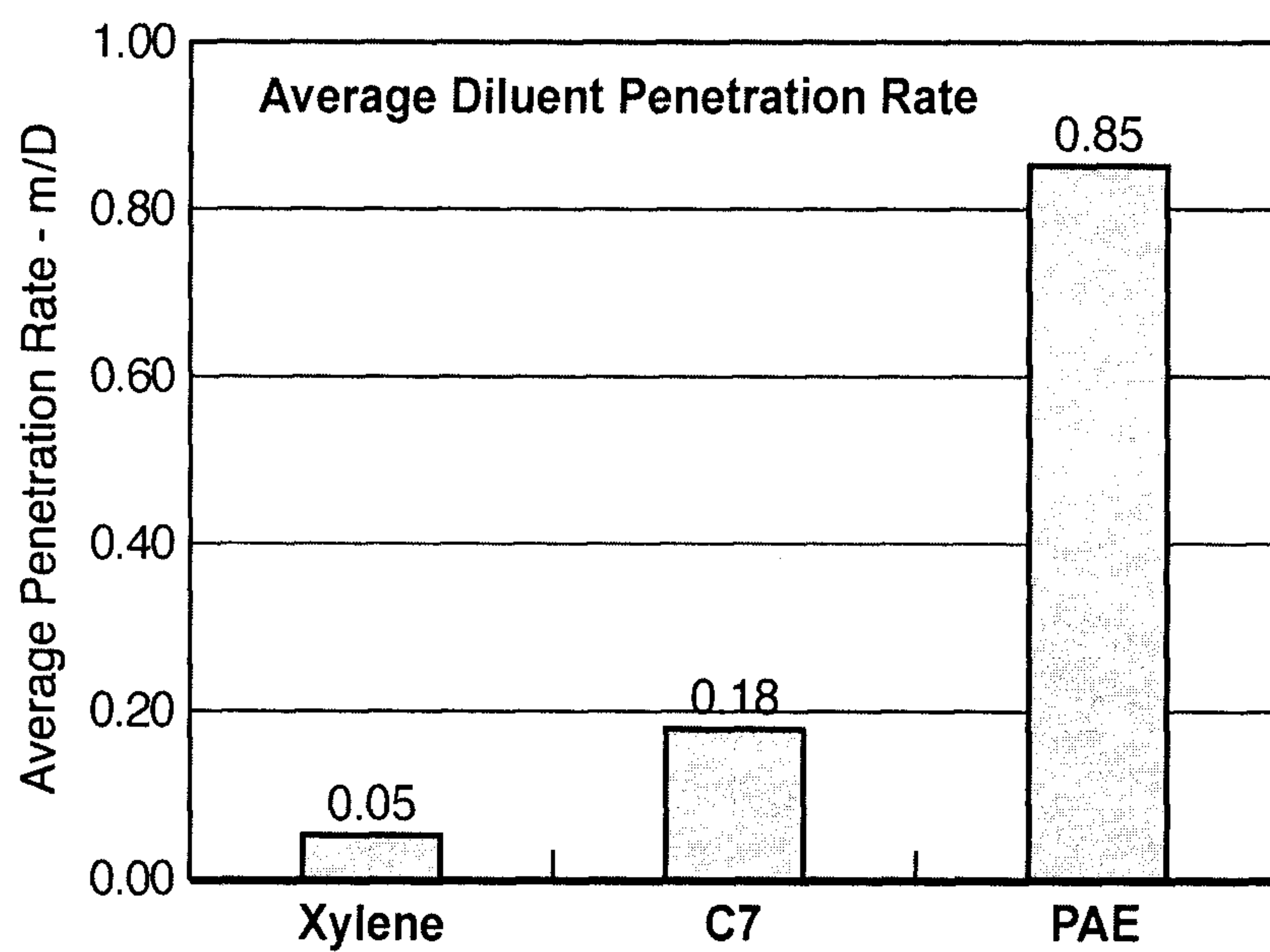
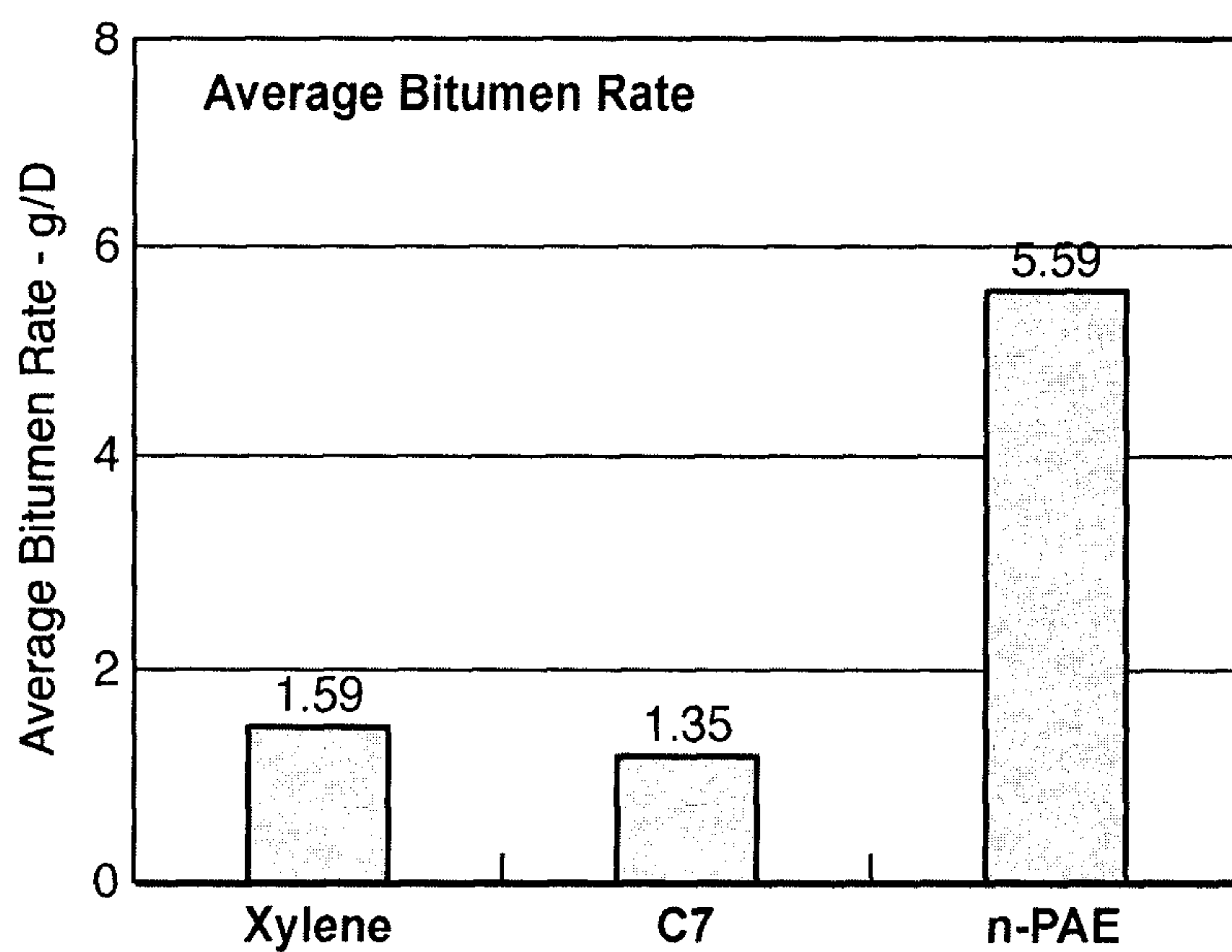
67. A start-up phase of a process for recovering viscous oil from an underground reservoir, comprising:

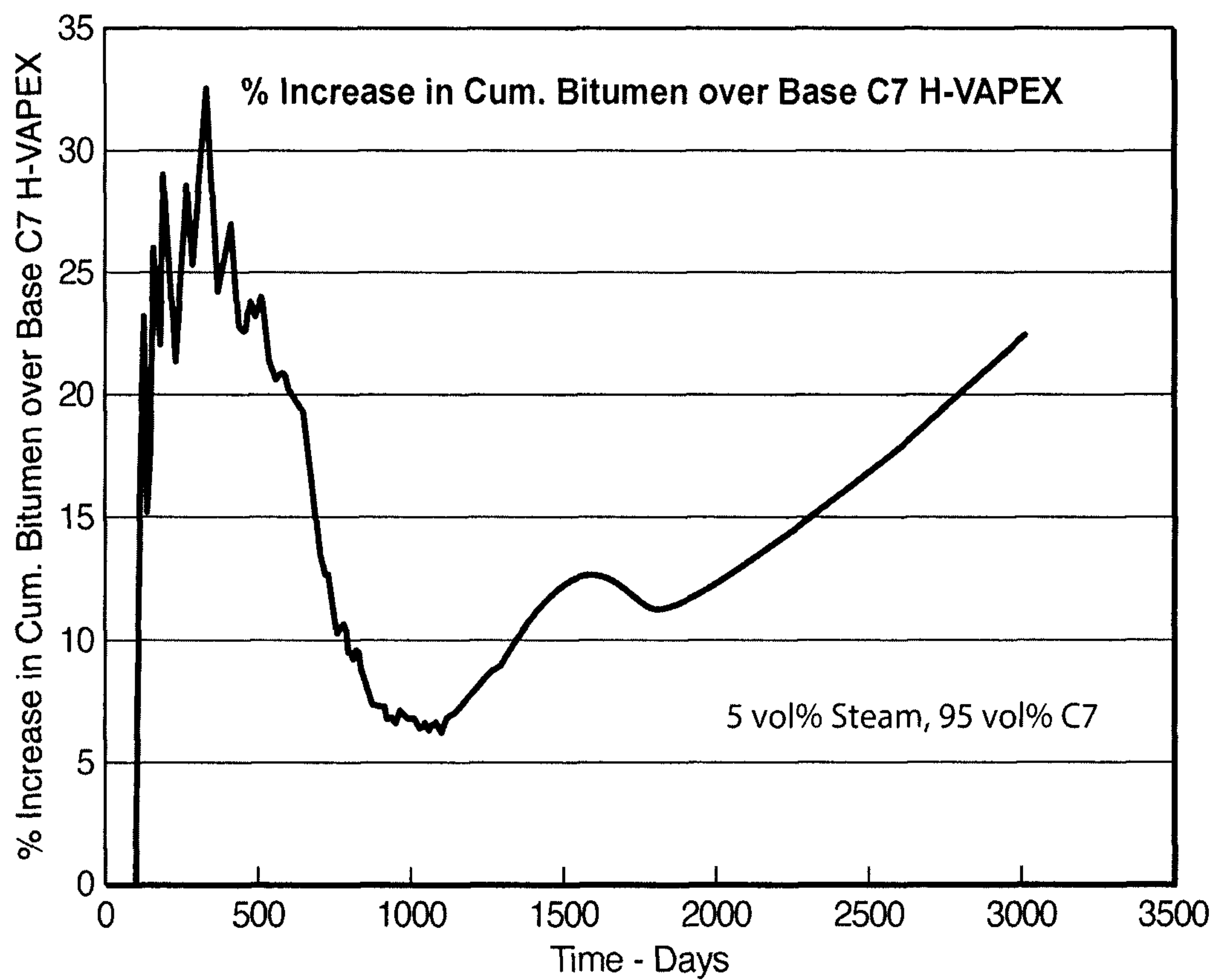
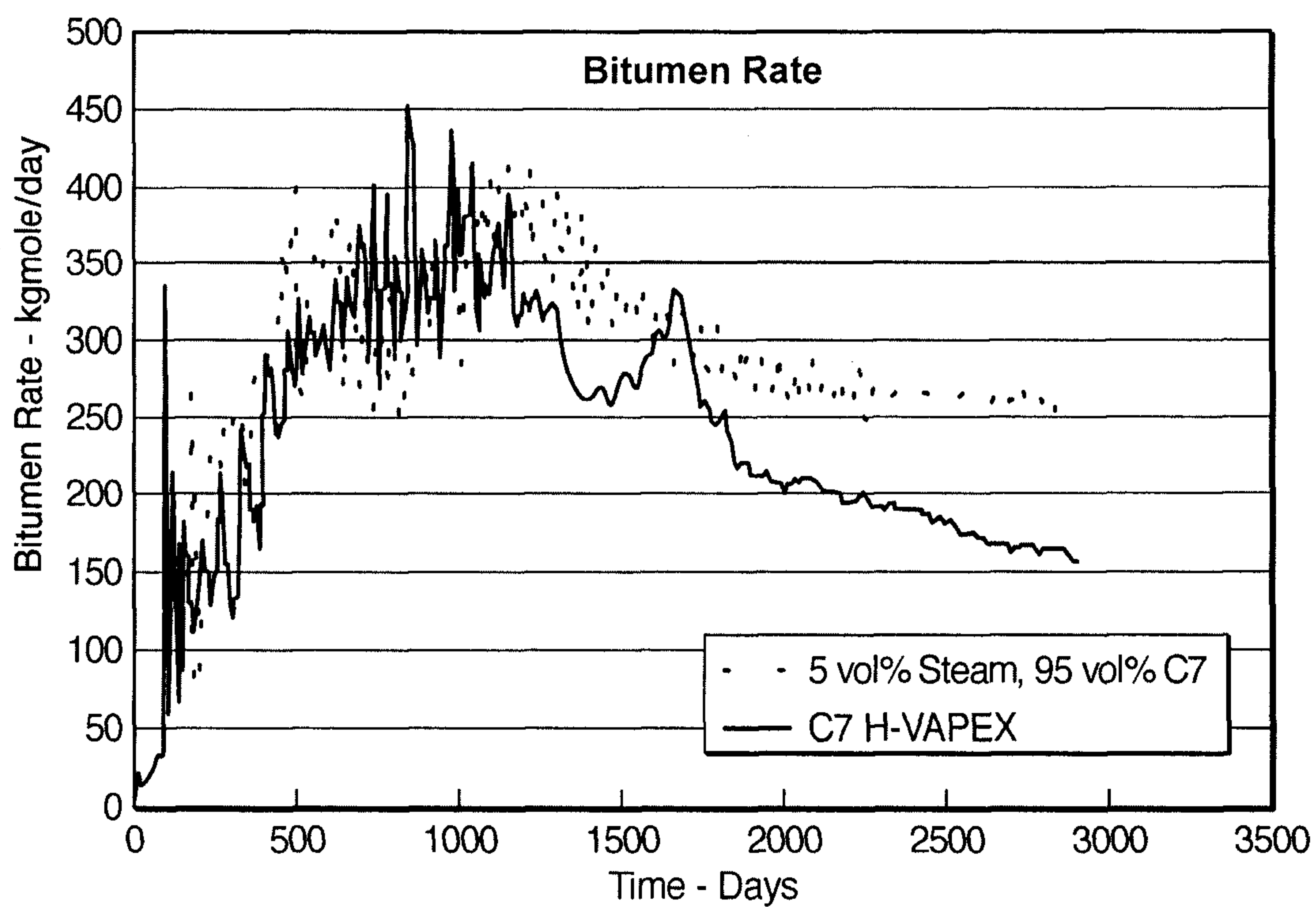
- a) providing the start-up composition according to any one of claims to 36 to 63;
- b) injecting the start-up composition of a) into the underground reservoir.

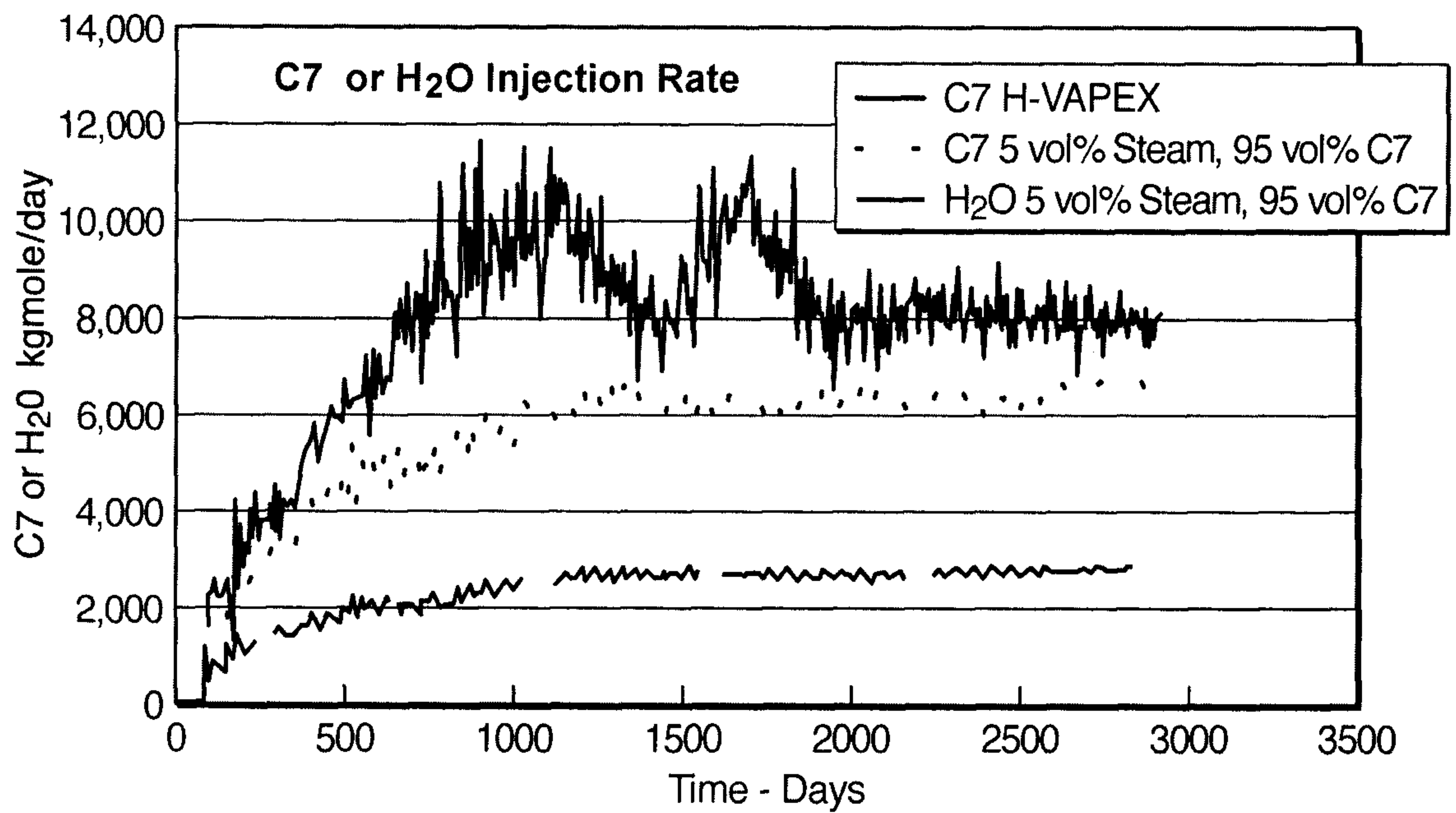
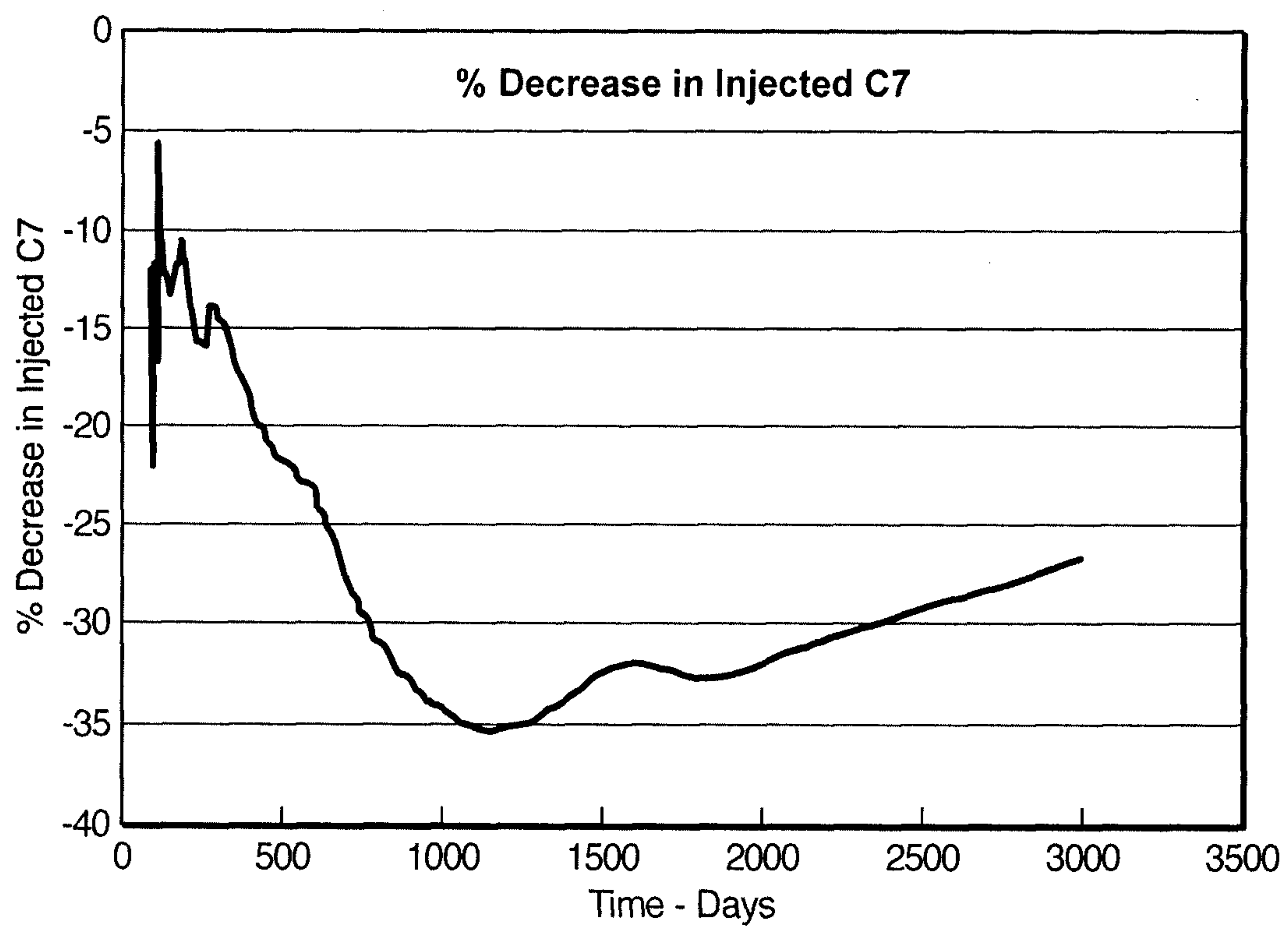
68. The process according to claim 67, wherein the start-up composition is injected at a temperature of 10-300°C.

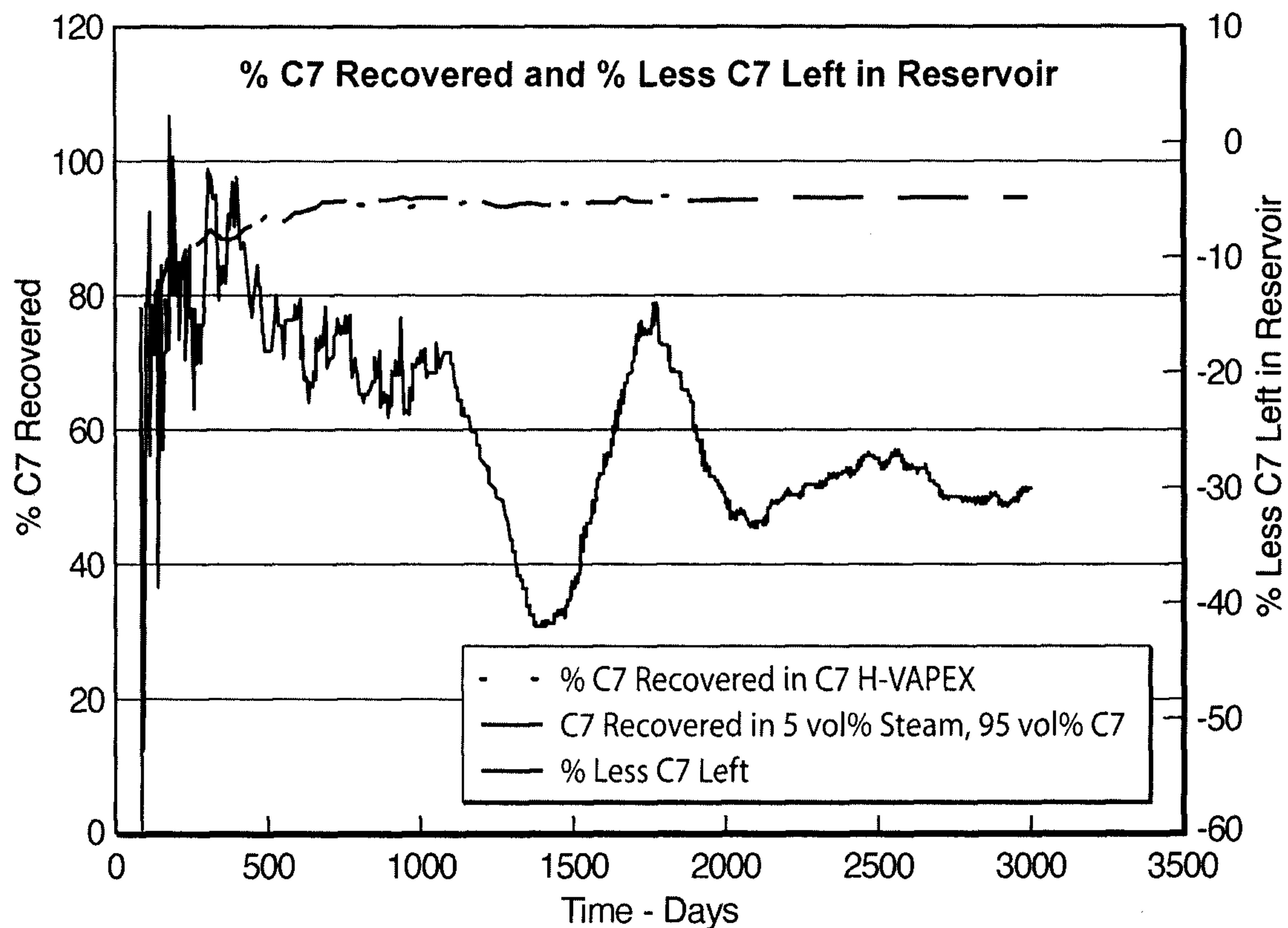
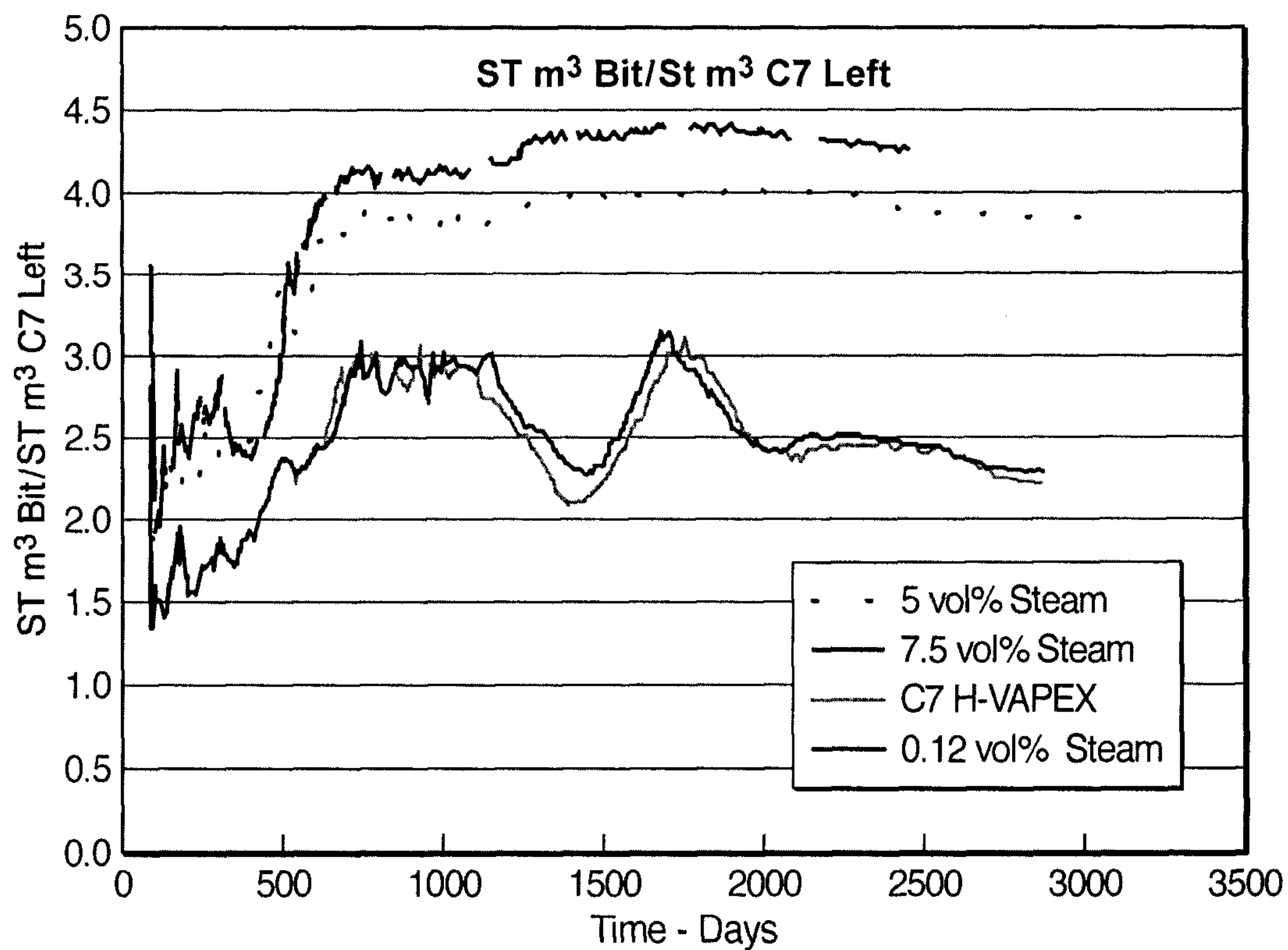
69. The process according to claim 67, wherein the start-up composition is injected at a temperature of 80-300°C.

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**FIG. 1****FIG. 2****FIG. 3**

2/10**FIG. 4****FIG. 5**

3/10**FIG. 6****FIG. 7**

4/10**FIG. 8****FIG. 9**

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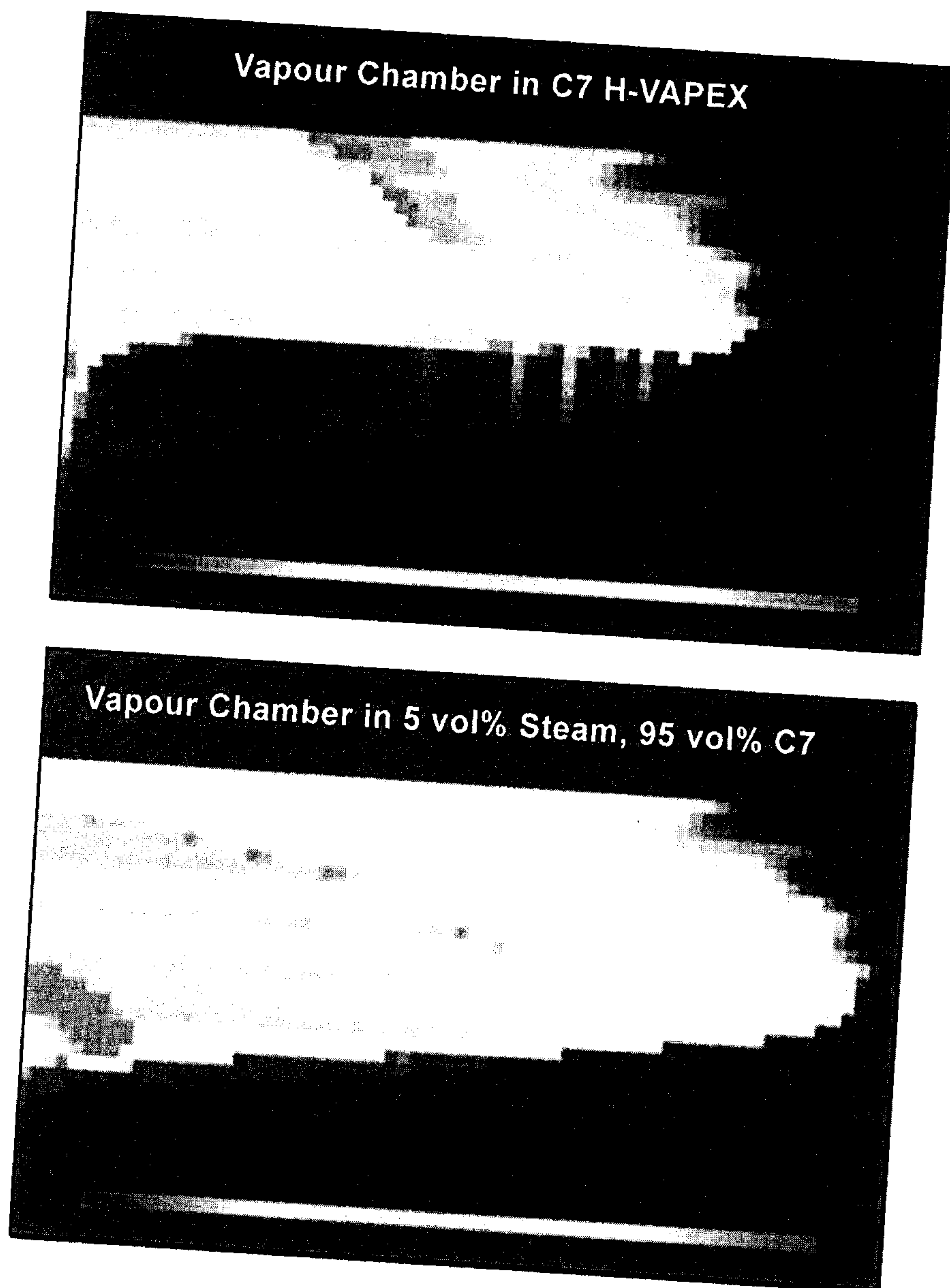
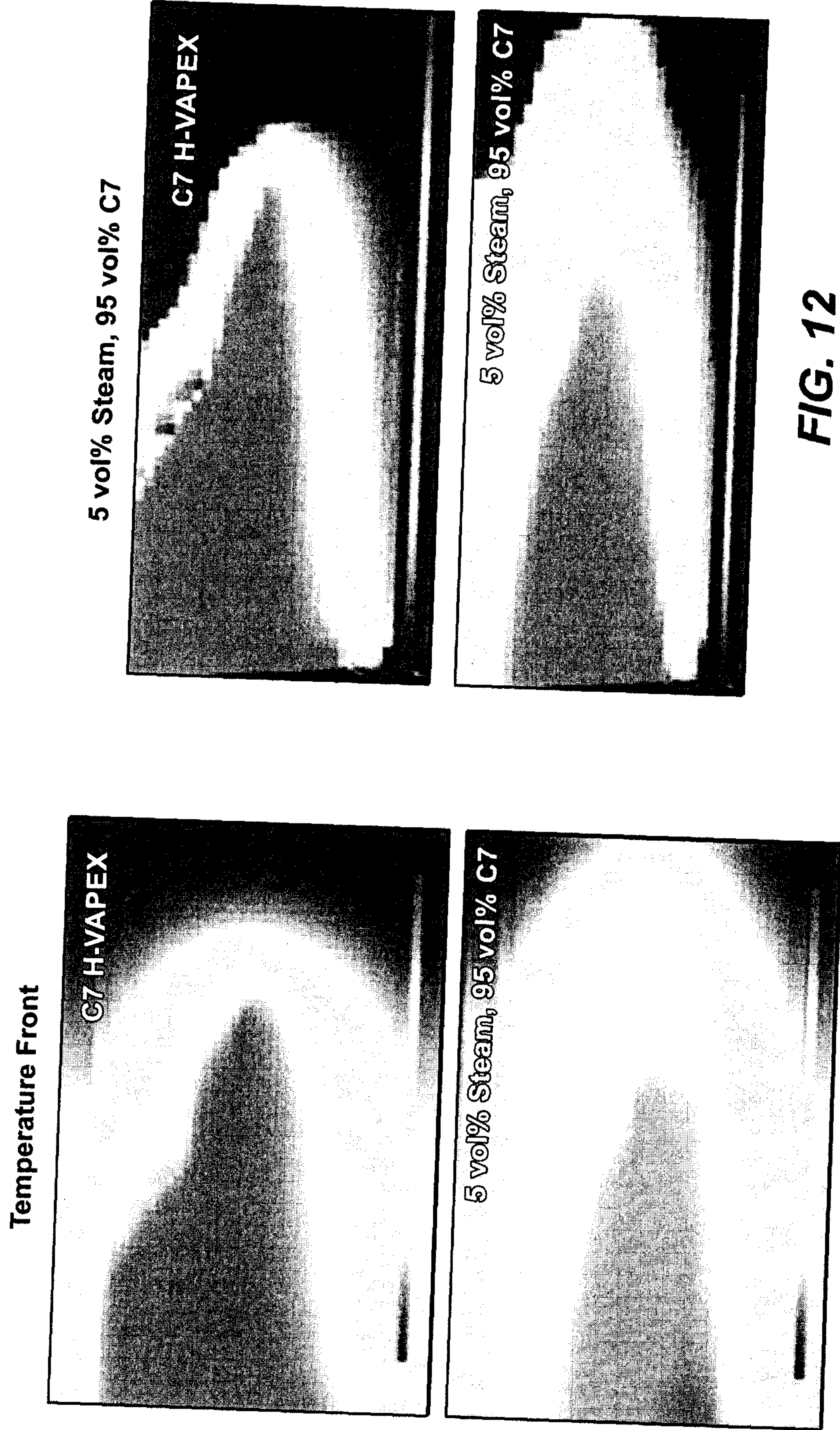
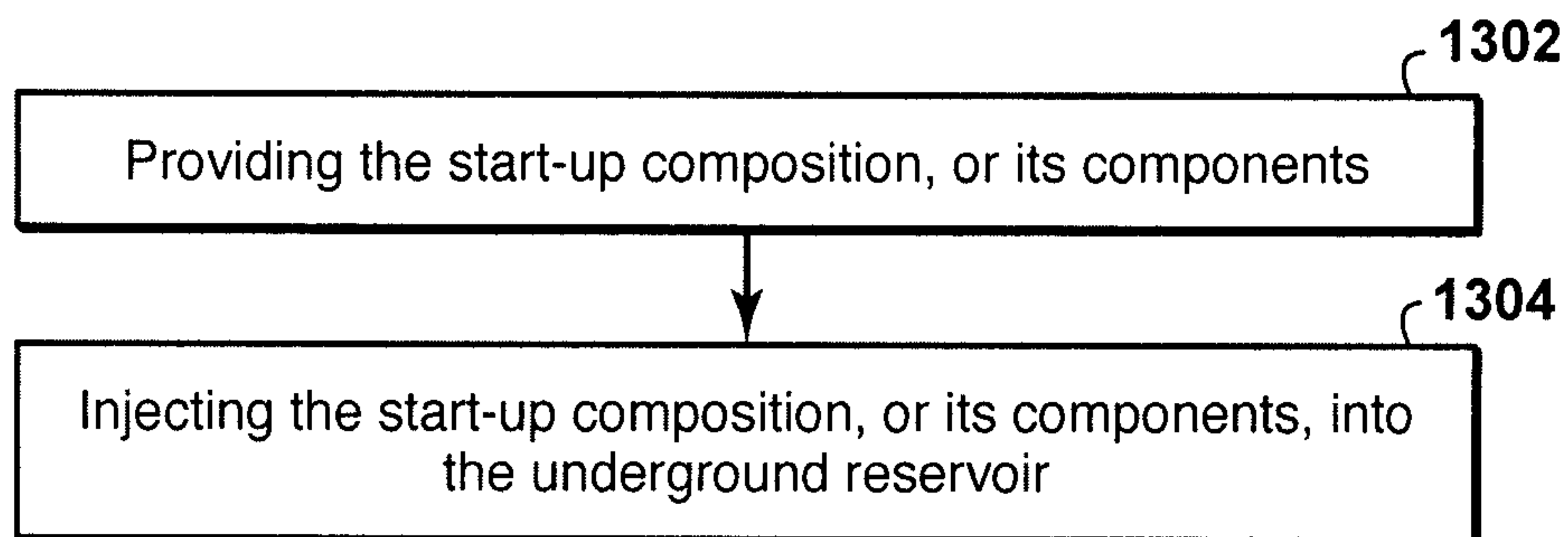
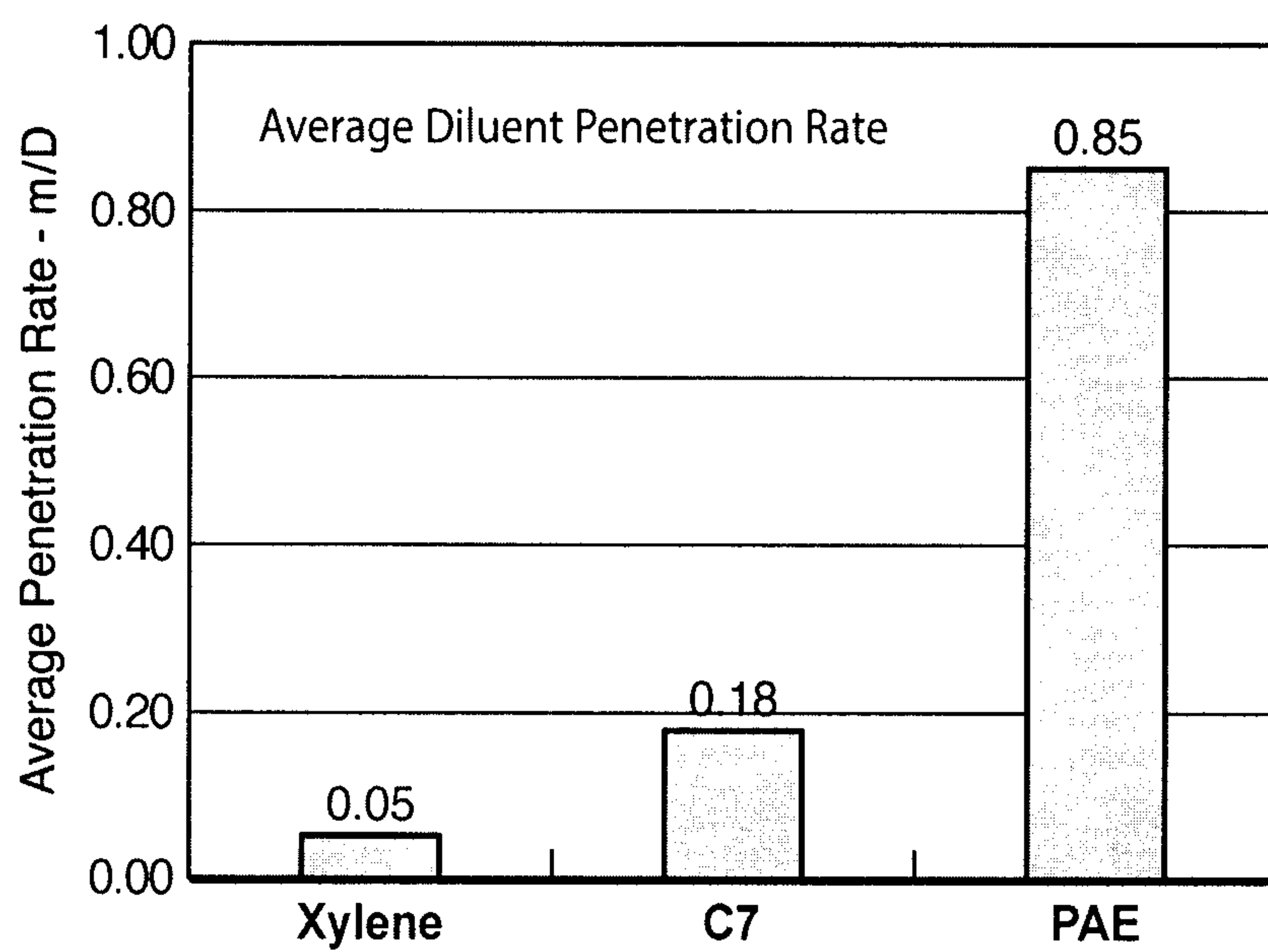
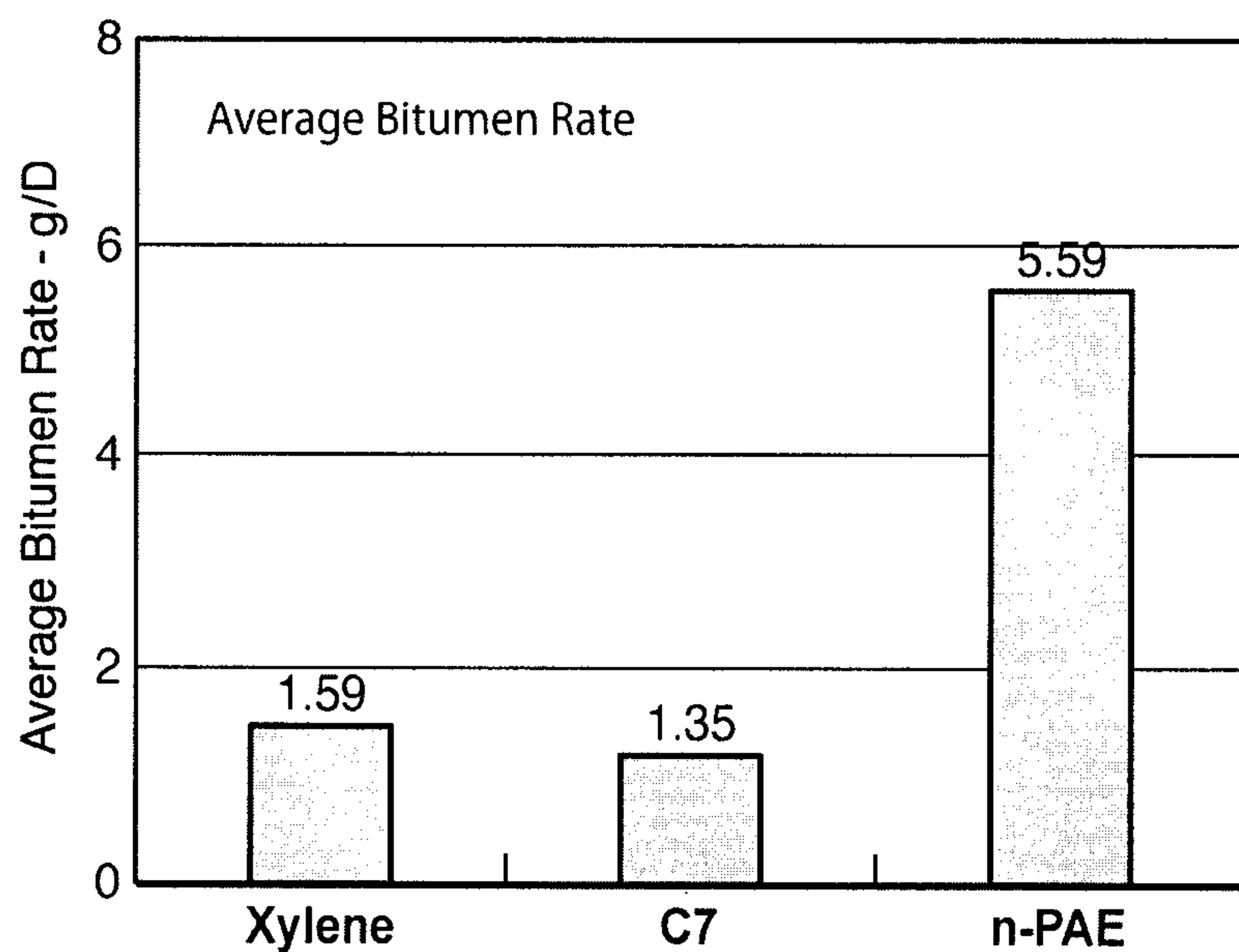


FIG. 10

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7/10**FIG. 13****FIG. 14****FIG. 15**

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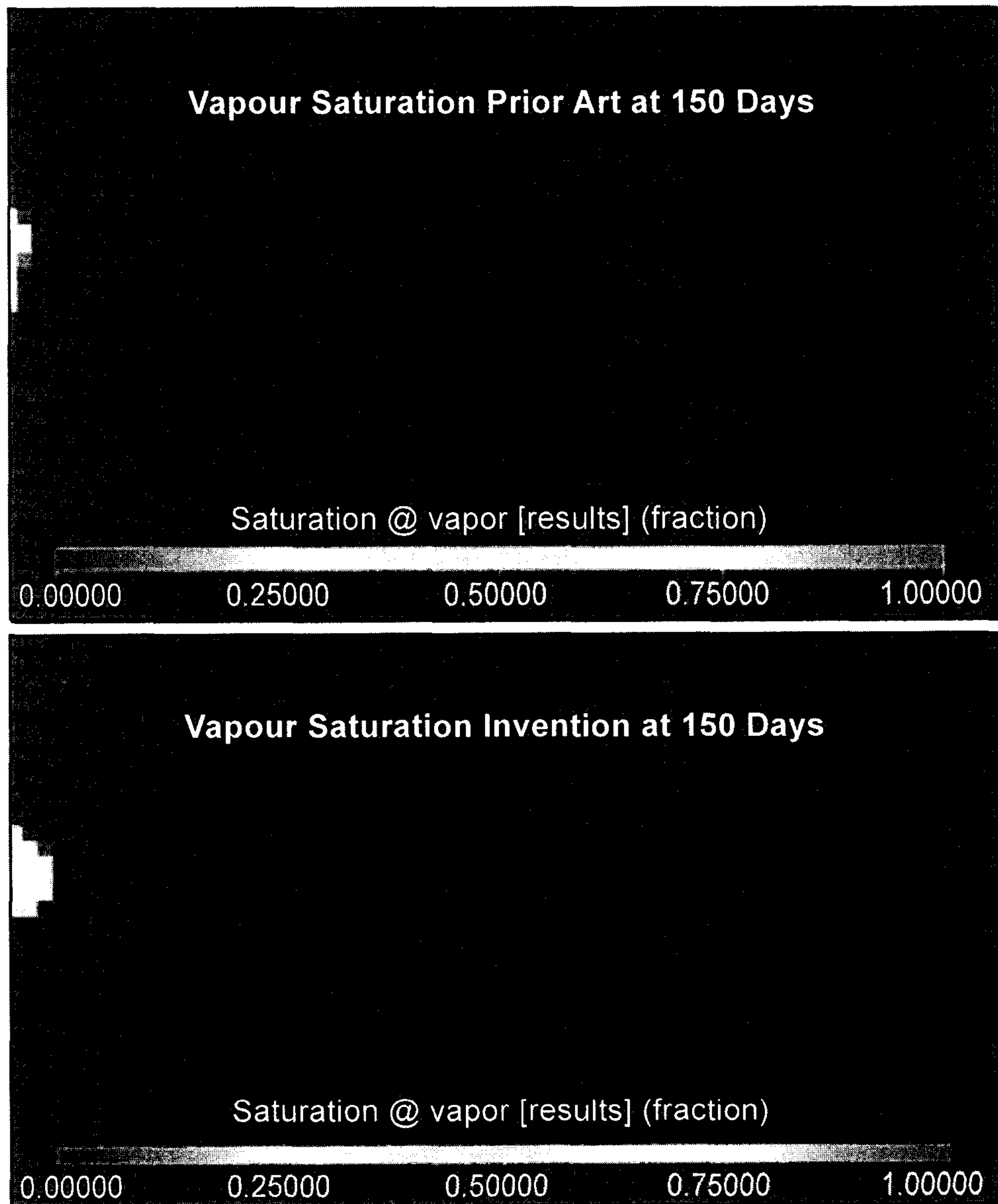


FIG. 16

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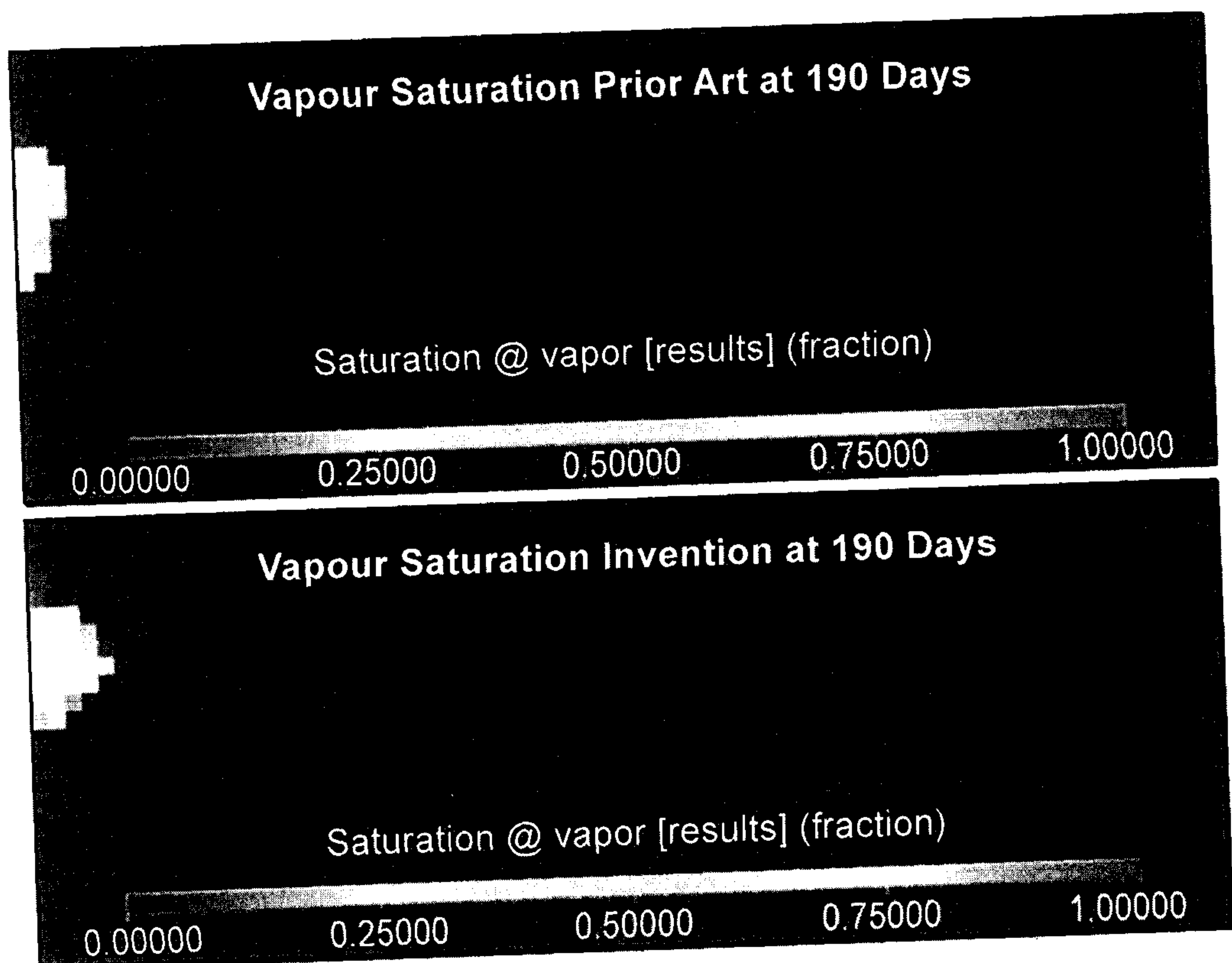
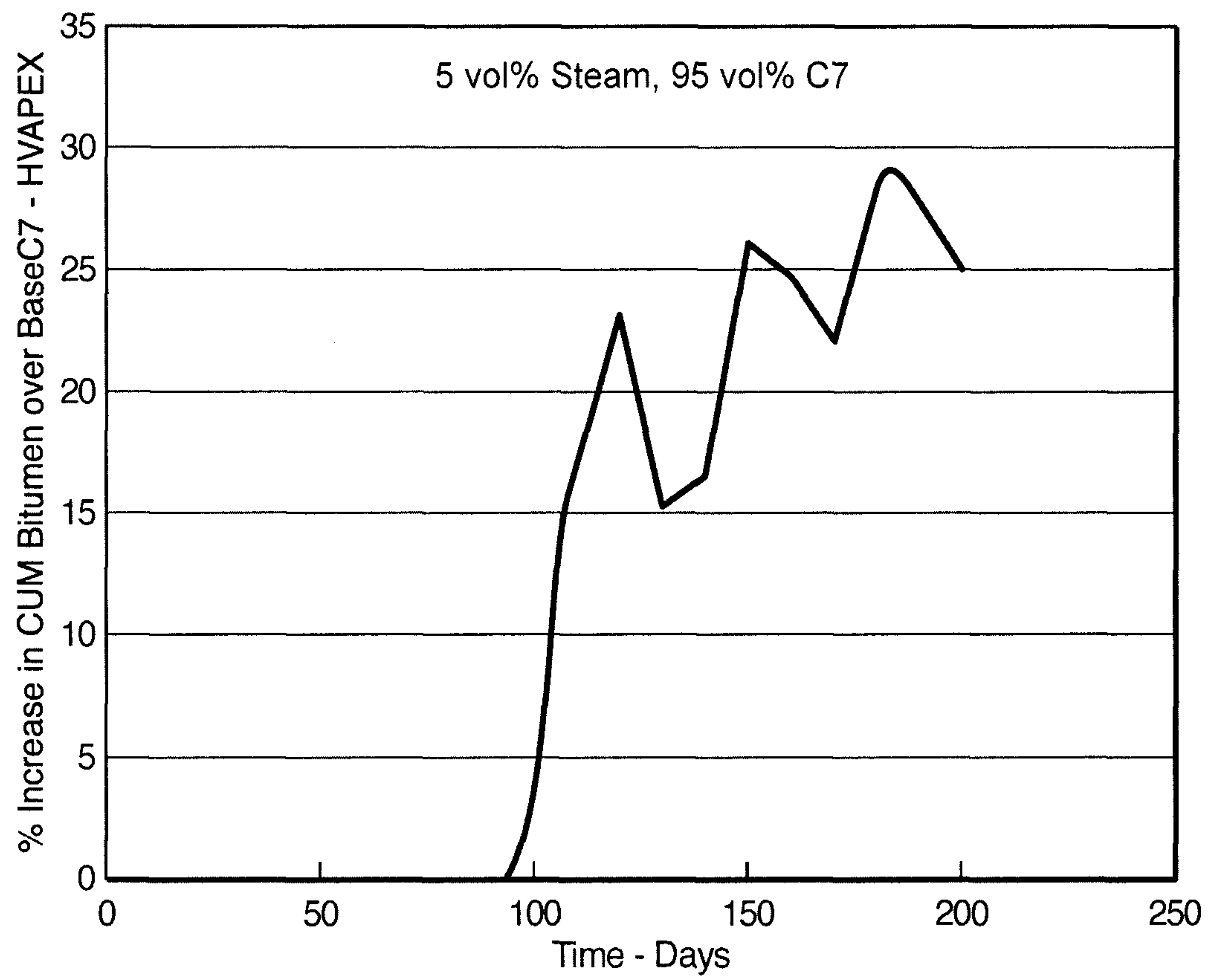


FIG. 17

10/10**FIG. 18**