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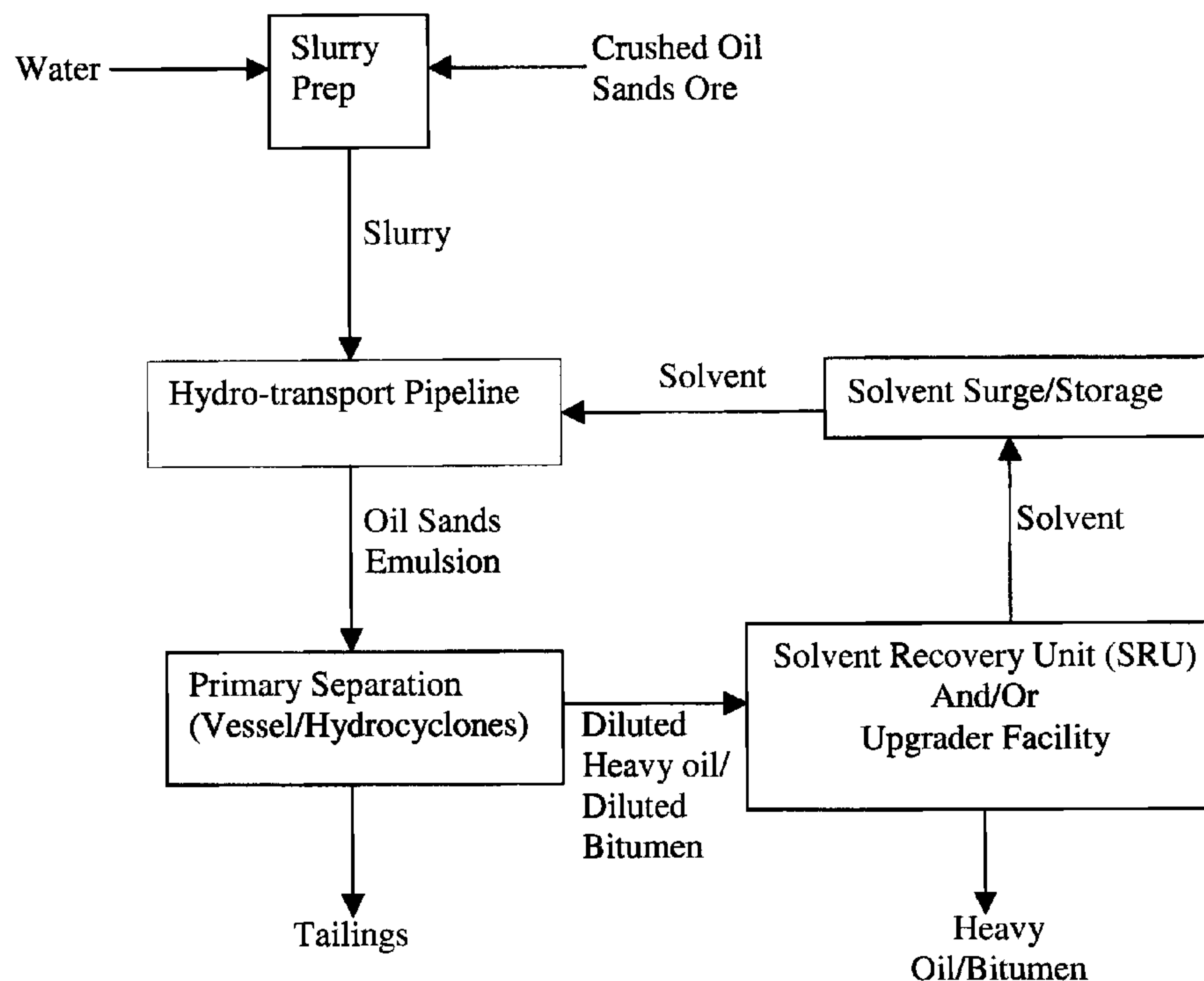
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(54) Titre : METHODE POUR EXTRACTION DIRECTE D'HUILE LOURDE DE SABLES BITUMINEUX AU MOYEN D'UN
SOLVANT HYDROCARBONE

(54) Title: METHOD FOR DIRECT SOLVENT EXTRACTION OF HEAVY OIL FROM OIL SANDS USING A
HYDROCARBON SOLVENT



(57) Abrégé/Abstract:

There is provided a method comprising: a) preparing a slurry having a temperature of between about 5°C and about 85°C by mining an oil sand deposit to produce a mined oil sand and mixing the mined oil sand with water; b) mixing the slurry with at least one hydrocarbon solvent thereby producing a solvent-slurry mixture; c) agitating the solvent-slurry mixture by transporting the solvent-slurry mixture along a pipeline, thereby producing an emulsion; and d) providing the emulsion to a primary separation facility.

ABSTRACT

There is provided a method comprising: a) preparing a slurry having a temperature of between about 5°C and about 85°C by mining an oil sand deposit to produce a mined oil sand and mixing the mined oil sand with water; b) mixing the slurry with at least one hydrocarbon solvent thereby producing a solvent-slurry mixture; c) agitating the solvent-slurry mixture by transporting the solvent-slurry mixture along a pipeline, thereby producing an emulsion; and d) providing the emulsion to a primary separation facility.

METHOD FOR DIRECT SOLVENT EXTRACTION OF HEAVY OIL FROM OIL SANDS USING A HYDROCARBON SOLVENT

TECHNICAL FIELD

This invention relates to the field of mining. In particular, extracting heavy oil and/or bitumen from oil sands using hydrocarbon solvents.

BACKGROUND

US 6,214,213 to Tipman *et al.* describes a treatment process for a froth produced by a water extraction process practiced on oil sands in which the froth, having been recovered from a primary separation vessel, is treated by adding a paraffinic solvent to the froth and mixing the solvent with the froth to induce inversion.

US 6,007,708 to Allcock *et al.* describes a method for recovering bitumen from oil sands by mixing mined oil sand with water to produce a slurry and pumping the slurry through a pipeline to a primary separation vessel and separating the slurry in the primary separation vessel into froth, middlings and tailings.

CA 857306 to Dobson describes a hot water process for treating bituminous tar sands. Dobson describes forming a mixture of bituminous sands and water and separating the mixture into a primary froth, a middlings layer and a tailings layer followed by further processing of the middlings layer.

CA 2,445,645 to Bara *et al.* describes a process for treating an aqueous aerated oils sand slurry by concentrating bitumen by injecting the slurry into an elongate closed vessel, passing the injected slurry through the elongate closed vessel and into a separation vessel.

UK 2,044,796 to Robinson *et al.* describes a process for extracting bitumen from oil sands by conditioning the oil sands with cold water, removing the resulting dispersion of clay and further treating with hot water.

US 3,527,692 to Titus describes a method for simultaneous transportation and recovery of shale oil from a slurry by transporting the slurry in a pipeline and heating the slurry to a temperature of between 550°F to 600°F.

US 3,556,980 to Clark *et al.* describes a process for removing water from a bituminous emulsion and recovering the bitumen by imparting shearing energy to an aqueous bituminous emulsion to coalesce and remove the water.

US 3,575,842 to Simpson describes a process for extracting a soluble component from a particulate solid material by preparing a slurry; passing the slurry, in a series of slugs separated by slugs of gas, in a conduit; withdrawing and injecting liquid at various points along the conduit; and collecting the withdrawn liquid.

US 3,925,189 to Wicks describes an improved method of pipeline transporting and recovering hydrocarbons from tar sands. Wicks describes mixing the tar sands with a solvent to form a slurry and pumping the slurry uphill at an angle of between 5° and 7° to the horizontal to encourage release of the hydrocarbons for the slurry by the time the slurry has reached the terminal end of the pipeline.

US 3,993,555 to Park *et al.* describes a method for extracting bitumen from tar sand by contacting the bitumen in the tar sand with a solvent having a freezing point below the freezing point of water in the tar sand and subsequently separating the solvent-bitumen mixture by freezing the water in the tar sand.

US 4,946,597 to Sury describes a process for separating a recovering bitumen from tar sands by mixing cold slurry with a flotation agent and a frothing agent and subjecting the resulting mixture to froth floatation for recovery of a bitumen product.

US 5,039,227 to Leung *et al.* describes a mixing circuit for slurring oil sand in water. Leung *et al.* describes a process for mixing the oil sand with water to produce a slurry by introducing a stream of recycled slurry into a circular mixing chamber formed by an open-topped mixer vessel to vortex water and oil sand into a slurry.

US 5,264,118 to Cymerman *et al.* describes a process for simultaneously transporting and conditioning oil sands by mixing the oil sand with hot water, entraining air into the mixture to form an aerated slurry and pumping the slurry through a pipeline.

US 5,626,743 to Humphreys describes a hot water extraction process for extracting bitumen from tar sands. Humphreys describes providing a slurry comprising tar sand, hot water and a conditioning agent, mixing and aerating the slurry to form a froth and separating the froth from the slurry.

US 5,746,909 to Calta describes a process for recovering tar from tar sands by forming a slurry comprising tar sand, an anionic surfactant, at least one high boiling alkane and water. The slurry is mixed to form a mixture of tar-free sand and an emulsion comprising tar. The emulsion is separated from the sand and then further treated to recover the tar.

US 5,770,049 to Humphreys describes a process for extracting bitumen from tar sands by providing a slurry comprising tar sand, hot water and a conditioning agent including an

alkali metal bicarbonate and mixing and aerating the slurry to produce a froth and separating the froth from the slurry.

SUMMARY

This invention is based in part on the discovery that an extraction of a heavy oil from an oil sand ore directly into a solvent phase is efficient and that a solubility of a heavy oil fraction of an oil sand ore in a solvent is more effective for extracting heavy oil from the oil sand ore than ablation of the oil sand ore. The percent of heavy oil recovery is independent of ore grade. Secondary floatation, addition of air, caustic, diesel, conditioning agents, and frothing agents are not required to increase recovery of heavy oil.

In various embodiments, there is provided a method comprising: a) mixing a slurry with at least one hydrocarbon solvent thereby producing a solvent-slurry mixture; b) agitating the solvent-slurry mixture thereby producing an emulsion; and c) providing the emulsion to a primary separation facility. The method may further comprise preparing the slurry by mining an oil sand deposit to produce a mined oil sand and mixing the mined oil sand with water. The method may further comprise recovering a heavy oil fraction from the emulsion at the primary separation facility.

In another embodiment, there is provided a method comprising: a) preparing a slurry having a temperature of between about 5°C and about 25°C by mining an oil sand deposit to produce a mined oil sand and mixing the mined oil sand with water; b) mixing the slurry with at least one hydrocarbon solvent thereby producing a solvent-slurry mixture; c) agitating the solvent-slurry mixture by transporting the solvent-slurry mixture along a pipeline, thereby producing an emulsion; and d) providing the emulsion to a primary separation facility. The method may further comprise recovering a diluted heavy oil fraction from the emulsion at the primary separation facility. The mixing may also be provided in the pipeline.

In various embodiments, there is provided a method comprising: a) preparing a slurry having a temperature of about 5°C to about 25°C by mining an oil sand deposit to produce a mined oil sand comprising a heavy oil adhered to an inert particles and mixing the mined oil sand with water; b) mixing the slurry with at least one hydrocarbon solvent to produce a solvent-slurry mixture; c) agitating the solvent-slurry mixture by transporting the solvent-slurry mixture along a pipeline, to produce an emulsion comprising i) a solution of the heavy oil dissolved in the hydrocarbon solvent ii) an aqueous phase and iii) the inert particles; and d) separating the phases of the emulsion into a diluted heavy oil fraction comprising the heavy oil

and a tailings fraction by applying a phase separation force over a phase separation period; wherein the heavy oil is separated from the inert particles by dissolving the heavy oil in the hydrocarbon solvent. The mixing may be provided in the pipeline. The pipeline may be a hydrotransport pipeline. The agitating may have a duration of at least two minutes.

In various embodiments, the phase separation force may be a G-force of at least 1, a G-force of between 1 and 4000, a G-force of between 1 and 1000, or a G-force of between 1 and 10. The phase separation force may be gravity, a centrifugal force or a centripetal force.

In various embodiments, the phase separation period is at least 4 minutes, less than 4 minutes, or between about 1 to about 4 minutes.

In various embodiments, the diluted heavy oil fraction may be recovered from the emulsion at a primary separation facility. The primary separation facility may be a primary separation vessel. The primary separation vessel may have a pressure rating greater than the vapour pressure of the hydrocarbon solvent at a maximum operating temperature. The primary separation vessel may have a vapour recovery unit. The primary separation vessel may have a volume that provides a minimum emulsion residence time of four minutes. The primary separation facility may be a hydrocyclone facility.

In various embodiments, the at least one hydrocarbon solvent may be a light hydrocarbon solvent. The at least one hydrocarbon solvent may be selected from the group consisting of: a branched alkane, an unbranched alkane, a cyclic alkane, and an aromatic hydrocarbon. The at least one hydrocarbon solvent may be at least one C₄ to C₁₆ alkane. The at least one hydrocarbon solvent may be at least two hydrocarbon solvents selected from the group consisting of: a branched alkane, an unbranched alkane, a cyclic alkane, and an aromatic hydrocarbon. The at least one hydrocarbon solvent may be a paraffinic solvent. The at least one hydrocarbon solvent may be a naphthenic solvent. The at least one hydrocarbon solvent may be selected from the group consisting of: benzene, toluene, xylene and ethyl benzene. The at least one hydrocarbon solvent may be selected from the group consisting of: n-pentane, naphtha, Varsol™, paint thinner, Naptha™, paraffinic solvent, reformat and hexane.

In various embodiments, the at least one hydrocarbon solvent may have a density of less than 0.9 g/mL, of between about 0.4 g/mL and about 0.9 g/mL, of between about 0.5 g/mL and about 0.8 g/mL, or of between about 0.6 g/mL and about 0.7 g/mL.

In various embodiments, the emulsion may have a temperature from about 5°C to about 25°C. The water may have a temperature from about 5°C to about 25°C.

In various embodiments, the slurry may have a density of about 1.1 g/cc to about 1.7 g/cc, of about 1.3 g/cc to about 1.65 g/cc, or of about 1.4 g/cc to about 1.5 g/cc.

In various embodiments, the emulsion may have a solvent to bitumen ratio of about 1.5:1 by weight to about 3:1 by weight, of about 1.5:1 by weight to about 2.5:1 by weight, or of about 2:1 by weight.

As used herein the term “hydrocarbon solvent” refers to a solvent that contains hydrogen and carbon, is capable of dissolving heavy oil and will separate from an aqueous phase when subjected to a phase separation force, such as gravity or centrifugal forces. The term “hydrocarbon solvent” also encompasses the term “light hydrocarbon solvent” as is commonly used in the art. A “light hydrocarbon solvent” is typically any non-polar, hydrophobic solvent that has a density less than 0.9 g/ml or less than diesel when measured at standard temperature and pressure.

As used herein, the term “paraffinic solvent” refers to an alkane solvent of the general formula C_nH_{2n+2} . The term “paraffinic solvent” is typically referred to by a skilled practitioner of the art as a blend of straight chain and/or branched chain and/or cyclic alkanes and/or alkenes and/or alkynes containing between 4 to 8 carbon atoms and the blend does not contain aromatic compounds. All of these definitions are intended to be covered by the single term “paraffinic solvent”.

As used herein the term “naphthenic solvent” refers to a cycloalkane solvent of the general formula C_nH_{2n} . A “naphthenic solvent” also encompasses “naphtha” as used by those skilled in the art. The term “naphtha” as used in the art, refers to a blend of hydrocarbon solvents having between 5 to 16 carbons and may contain aromatic groups. All of these definitions are intended to be covered by the single term “naphthenic solvent”.

As used herein the term “heavy oil” refers to the primary hydrocarbon component of an oil sand ore. These are typically types of crude oil, a naturally occurring petroleum. Crude oil comprises pentanes and heavier hydrocarbons. Crude oil is commonly classified as light, medium, heavy or extra heavy, referring to a gravity as measured on the American Petroleum Institute (API) Scale. The API gravity is measured in degrees and is calculated using the formula $API\ Gravity = (141.5/S.G.) - 131.5$.

Light oil has an API gravity higher than 31.1° (lower than 870 kilograms/cubic metre), medium oil has an API gravity between 31.1° and 22.3° (870 kilograms/cubic metre to 920 kilograms/cubic metre), heavy oil has an API gravity between 22.3° and 10° (920 kilograms/cubic metre to 1,000 kilograms/cubic metre), and extra heavy oil (e.g. bitumen) has

an API gravity of less than 10° (higher than 1,000 kilograms/cubic metre). The Canadian government has only two classifications, light oil with a specific gravity of less than 900 kilograms/cubic metre (greater than 25.7° API) and heavy oil with a specific gravity of greater than 900 kilograms/cubic metre (less than 25.7° API). As used herein “heavy oil” may refer to both heavy and extra heavy oils or any oil having an API less than 22.3° .

As used herein a “phase separation force” is a force that can be measured in G-forces. Gravity, centrifugal force and centripetal force are examples of phase separation forces.

As used herein a “phase separation period” is a duration of time required for the separation of a solution of heavy oil and hydrocarbon solvent to separate from an aqueous phase. The duration of time required may be dependent on the relative densities of the two phases and the magnitude of the phase separation force applied.

BRIEF DESCRIPTION OF THE DRAWINGS

Figure 1 is process flow diagram of methods described herein.

Figure 2 is a graph showing solvent to heavy oil (S:B) ratio vs. seconds of settling time at 10°C of the emulsion.

Figure 3 is a graph showing solvent to heavy oil (S:B) ratio vs. mg of solvent loss per Kg of water from the emulsion.

DETAILED DESCRIPTION

In one embodiment, there is provided a method comprising: A) preparing a slurry by mining an oil sand deposit to produce a mined oil sand and mixing the mined oil sand with water; B) mixing the slurry with at least one hydrocarbon solvent thereby producing a solvent-slurry mixture; C) agitating the solvent-slurry mixture thereby producing an emulsion; D) providing the emulsion to a primary separation facility; and E) recovering a heavy oil fraction from the emulsion at the primary separation facility.

A) Preparing Slurry

Oil sand, also referred to as tar sand or heavy oil sand, comprises water-wetted sand grains coated with heavy oil or bitumen. Large deposits of tar sands are found around the world, including Northern Alberta, Canada and the largest of these deposits, the Athabasca formation, extends from the surface to depths of over fifteen hundred feet below an overburden.

Oil sand deposits are composed primarily of particulate silica (sand) and a heavy oil content which varies from about 5% to more than 20% by weight. An average heavy oil content of an oil sand deposit is about 10% to about 12% by weight of the total oil sand deposit. Clay and silt component in an oil sand is from about 10% to about 30% by weight. Water content is from about 1% to about 10% by weight. The heavy oil is typically viscous having an API gravity of about 6° to about 20°.

An oil sand deposit can be broken up using mining techniques known to the skilled practitioner. For example, an oil sand deposit may be mined using heavy equipment such as drilling equipment, crushers, bulldozers, trucks and shovels to mechanically fragment the deposit. Alternatively, explosives and modern blasting techniques can be used to fragment the oil sand deposit or high-pressure water can be used to ablate the oil sand deposit. One or a combination of these methods may be used to produce a fragmented oil sand deposit.

A slurry is prepared by mixing the fragmented oil sand deposit with water. The water may be of any temperature (from 1°C to 99°C) and is often provided as extremely hot water in order to reduce the viscosity of the heavy oil, though it is not necessary for the operation of methods described herein to use hot water. Water is often provided at temperatures of between 50°C to 85°C to form a slurry having a temperature of between 25°C and 45°C. In one embodiment, the water added to the fragmented oil sand has a temperature of between about 1°C and about 50°C. In another embodiment, the water has a temperature of about 5°C to about 25°C. The water may have a temperature of 6°C, 7°C, 8°C, 9°C, 10°C, 11°C, 12°C, 13°C, 14°C, 15°C, 16°C, 17°C, 18°C, 19°C, 20°C, 21°C, 22°C, 23°C, or 24°C. The slurry, produced by addition of the water to the fragmented oil sand, behaves more like a fluid than the fragmented oil sand alone. The water in the slurry acts as a transportation medium in which the fragmented oil sand is carried.

The slurry may be produced with a density of about 1.1 g/cc to about 1.7 g/cc. In one embodiment, the density may be from about 1.3 g/cc to about 1.65 g/cc. The density may be 1.1 g/cc, 1.15 g/cc, 1.2 g/cc, 1.25 g/cc, 1.3 g/cc, 1.35 g/cc, 1.4 g/cc, 1.45 g/cc, 1.5 g/cc, 1.55 g/cc, 1.6 g/cc, 1.65 g/cc, 1.7 g/cc, 1.75 g/cc, 1.8 g/cc, 1.85 g/cc, 1.9 g/cc, or 1.95 g/cc. The slurry is typically produced with a density of about 1.5 g/cc, which may be achieved by mixing the water and the fragmented oil sand in an approximate “g of oil sand : ml of water” ratio of 2:1. These densities are generally achieved using water have a temperature of between about 10°C to about 30°C to produce a slurry having a temperature of between about 5°C to

about 25°C. Nevertheless, the skilled practitioner will be able to produce slurries having the desired density at any desired temperature.

B) Producing a Solvent-Slurry Mixture

The slurry is mixed with a hydrocarbon solvent to produce a solvent-slurry mixture. The hydrocarbon solvent used will be able to dissolve the heavy oil and separate from an aqueous phase, once a solution of heavy oil and solvent is achieved, when subjected to a G-force equal to or greater than 1. The hydrocarbon solvent will often be a non-polar, hydrophobic solvent having a density of between 0.4 g/mL and 0.9 g/mL when measured at standard temperature and pressure. The hydrocarbon solvent may have a density of 0.4 g/mL, 0.45 g/mL, 0.5 g/mL, 0.55 g/mL, 0.6 g/mL, 0.65 g/mL, 0.7 g/mL, 0.75 g/mL, 0.8 g/mL, 0.85 g/mL or 0.9 g/mL. The hydrocarbon solvent may be a substituted or unsubstituted, branched or unbranched, cyclic or non-cyclic, alkane, alkene, alkyne or aromatic hydrocarbon. The hydrocarbon solvent is often an alkane having a carbon chain of 4 to 16 carbon atoms. The hydrocarbon solvent may be a paraffinic solvent or a naphthenic solvent or a mixture thereof. Specific examples of hydrocarbon solvents include, but are not limited to: benzene, toluene, xylene, ethyl benzene, n-pentane, hexane, naphtha, Varsol™, Naptha™, paint thinner and mixtures thereof.

The solvent-slurry mixture may be produced to have a solvent to heavy oil ratio of between about 1.5:1 to about 3:1 by weight. The solvent to heavy oil ratio, by weight, may be 1.5:1, 1.6:1, 1.7:1, 1.8:1, 1.9:1, 2:1, 2.1:1, 2.2:1, 2.3:1, 2.4:1, 2.5:1, 2.6:1, 2.7:1, 2.8:1, 2.9:1 or 3:1.

In a particular embodiment, the solvent is added to the slurry in a pipeline. The pipeline may be, for example, a hydrotransport pipeline. Pipeline operating pressure may range from atmospheric pressure to 3500 kPag, though it is possible that higher pressures may be realized in future designs.

The slurry may be added to the pipeline first and the solvent added to the slurry after the slurry has traveled along the pipeline a distance. The solvent and the slurry may be added to the pipeline simultaneously. The solvent may be added to the pipeline first and the slurry added to the pipeline after the solvent has traveled along the pipeline for a distance. The solvent and the slurry may be added to the pipeline simultaneously or at separate times, but the solvent and the slurry should be made to contact each other such that the ratio of the solvent to the heavy oil is between about 1.5:1 to about 3:1 by weight.

If solvent to heavy oil ratios exceed 3:1, then a rag layer begins to form. A rag layer is a layer that forms upon precipitation of asphaltenes. A rag layer becomes detrimental to the process when the layer becomes so thick that it hinders separation of the emulsion. The larger the rag layer becomes, the more energy that will be required to recover the heavy oil.

Oil sand ore particles have an intrinsic water layer in between the surface of an inert particle (e.g. sand) and the heavy oil in the ore. The intrinsic water layer provides a barrier to the hydrocarbon solvent such that the hydrocarbon solvent does not attach to the surface of the inert particle. Adding the hydrocarbon solvent to the slurry causes the heavy oil to dissolve into a solvent phase, thereby producing a solution. The solution comprises the heavy oil dissolved in the hydrocarbon solvent.

C) Producing the Emulsion

The solvent-slurry mixture is agitated to produce the emulsion. The emulsion comprises the water (from both the intrinsic water layer and the added water), the solution of the heavy oil and the hydrocarbon solvent, and the inert material in the oil sand ore. These three components of the emulsion form two phases of the emulsion: a diluted heavy oil fraction and a tailings fraction. The agitating is sufficiently turbulent so as to promote contact between the various components of the emulsion. Any air entrained during the agitation will de-aerate rapidly and easily due to the low viscosity of the diluted heavy oil fraction. Air blowers are not required for methods described herein. The emulsion generally behaves like conventional oil and water emulsions found in oil systems.

Agitating the solvent-slurry mixture causes more of the heavy oil to dissolve in the hydrocarbon solvent. The solution has a viscosity and a density that is less than the viscosity and the density of the heavy oil. The density and the viscosity of the solution is lower than that of the water. The density and the viscosity of the solution is less than that of the water at temperatures of between about 1°C to about 99°C, of between about 1°C to about 50°C, of between about 5°C and about 25°C, and of between about 5°C and 10°C.

Agitating the solvent-slurry mixture may be achieved by transportation of the solvent-slurry mixture along a pipeline, typically the pipeline is a hydrotransport pipeline. The pipeline may be uphill, downhill, horizontal or a combination thereof. The pipeline may have a pump or a plurality of pumps to facilitate transportation of the materials in the pipeline. The pump may also facilitate the agitation of the solvent-slurry mixture. The pipeline may also be heated. The heating may be for the purposes of heating the solvent-slurry mixture to a desired

temperature, or simply to ensure that the solvent-slurry mixture does not freeze when an outdoor temperature around the pipeline is below a freezing temperature of a fluid in the pipeline.

The difference in: a) the viscosity and the density of the water; and b) the viscosity and the density of the solution results in the emulsion being an unstable emulsion. The emulsion will separate over time using only gravity as a means for separation. Gravity will also separate the inert material from the oil sand ore from both the water and the solution. The rate of separation of the solution and the water from the emulsion is determined by the difference between the viscosity and the density of the solution compared with the water. If there is a large difference between the viscosity and the density of the solution when compared with the water, then the emulsion will separate quickly. If there is a small difference between the viscosity and the density of the solution when compared with the water then the emulsion will separate slowly. Figure 2 describes the relationship between a solvent:heavy oil ratio of the emulsion and the settling time required.

It is also possible to separate the emulsion using other known separation techniques, including, but not limited to, hydrocyclones, centrifuges and other gravity, centripetal force or centrifugal force generating machines.

D) Primary Separation Facility

The emulsion is separated into a diluted heavy oil product and a tailings fraction at a primary separation facility. Separation techniques are known in the art and a typical primary separation facility is a primary separation vessel.

A primary separation vessel is a body that holds the emulsion for a phase separation period sufficient to allow a gravitational separation of the emulsion to occur. The diluted heavy oil fraction will float to the top of the separated emulsion and the tailings fraction will sink to the bottom of the separated emulsion. The bottom of the primary separation vessel is often equipped with a flush nozzle in order to remove the tailings as they build up.

The emulsions produced by methods described herein will clean phase separate into a diluted heavy oil and a tailings fraction. Furthermore, the clean phase separation occurs without the need to de-aerate using heat, steam treatment or mechanical energy. The separated diluted heavy oil product may be skimmed from the surface of the separated emulsion in the primary separation vessel or be collected in an overflow launder. Significantly, there is no

middling layer formed within the primary separation vessel. Thus, the conventional requirements to remove a middling layer and process through a flotation cell is not required.

Separating the emulsion may be achieved by subjecting the emulsion to G-forces of 1 or higher. G-forces of 1, 2, 3, 4, 5, 6, 7, 8, 9 or 10 may be used to separate the emulsion. The larger the G-force that is applied, the less time that is required for separation to occur. G-forces may be applied by simply allowing gravity to act on the emulsion, or by providing rotational velocity to the emulsion. Rotational velocity can be applied by means of a centrifuge or a hydrocyclone.

Another type of primary separation facility is a hydrocyclone facility. These facilities are capable of separating liquids of different densities and solids from liquids by providing centrifugal forces to the emulsion. The liquids of different densities accelerate at different rates when the same centrifugal force is applied to them, resulting in a separation of the liquids with different densities.

The phase separation period will be dependent on the magnitude of the separation force applied to the emulsion. The phase separation period may be less than 4 minutes, greater than 4 minutes, or between about 1 minute to about 4 minutes. The phase separation period may be 30 seconds, 1 minute, 1.5 minutes, 2, minutes, 2.5 minutes, 3, minutes, 3.5 minutes and 4 minutes.

The diluted heavy oil, once separated from the emulsion is sent to a solvent recovery unit or to an upgrader facility to further process the diluted heavy oil into a commercial oil product and to recover the solvent. Once the solvent is removed from the diluted heavy oil product, it may be recycled and reused. Some solvent will not be recoverable and Figure 3 describes the relationship between the solvent:heavy oil ration of the emulsion and the mg of solvent lost per Kg of water.

E) Recovering Heavy Oil and Solvent

The diluted heavy oil product may be delivered to a solvent recovery unit. The solvent recovery unit removes the solvent from the diluted heavy oil product by heating the diluted heavy oil product in a solvent recovery column so that the solvent vapourizes and is separated from the heavy oil. The vapourized solvent is collected by condensing the vapourized solvent in a solvent condenser and may be recycled for use in preparation of the solvent-slurry mixture. The leftover heavy oil may then be sent to an upgrader facility to upgrade the heavy oil into a

commercial oil product. Techniques well known to the skilled practitioner in the art may be used to recover the solvent and upgrade the heavy oil.

EXAMPLES

Example I

200 gram samples of average grade oil sand containing 10 wt.% bitumen (as determined by Dean-Stark method) were mixed with 100 ml of water in individual containers to form a slurry having a density of about 1.5 g/cc, the temperature of the slurry was approximately 15 degrees C.

To the first four sample containers n-pentane solvent was added at solvent:bitumen ratios ranging from 1.5:1 to 6:1. Several tests were repeated at 2:1 solvent:bitumen with the oil sands in the form of large lumps. The containers were sealed and shaken by hand for 45 seconds to 2 minutes in duration. Each sample container was observed for settling time, interphase, presence of solids in the diluted bitumen layer and bitumen in the solids/slurry. .

Several tests were also conducted with a commercially available naphtha at solvent:bitumen ratios of 2:1, along with commercial Varsol™ and a typical over-the-counter paint thinner.

The average settling time for an n-pentane test at a solvent:bitumen of 2:1 was four minutes, with a light diluted bitumen product that appeared to contain no solids or water, a clean interphase and a visually clean solids phase. Settling times increased with solvent:bitumen ratio. Samples treated with the paint thinner behaved similarly to the n-pentane tests.

A solvent:bitumen ratio of 6:1 n-pentane yielded a settling time of approximately 20 seconds, with clean washed solids. The formation of a rag layer at the interphase of the water/hydrocarbon layers was also observed.

Solvent:bitumen ratios of 1.5:1 resulted in settling times upwards of 7-9 minutes, an ill-defined/dirty interphase between the slurry and diluted bitumen phases and presence of bitumen on the solids.

Average settling times with the naphtha solvent at 2:1 solvent:bitumen ratio were in the order of 5-6 minutes, with a rough interphase and the presence of globular bitumen in the slurry phase. Samples tested with Varsol™ had similar results to the naphtha.

Example II

100 gram samples of average grade oil sand containing 11.2 wt.% bitumen (as determined by Dean-Stark method) were mixed with 50 ml of water in individual containers to form a slurry having a density of about 1.5 g/cc, the temperature of the slurry was maintained at 10 degrees C.

To the slurry samples was added paraffinic solvent consisting of approximately 50% pentanes and 50% hexanes (by volume) at solvent:bitumen ratios ranging from 2:1 to 3:1 and each test was performed in duplicate.

The containers were sealed and shaken by machine on a moderate shaking setting for 2 minutes as to simulate the conditions found within a hydro-transport pipeline. (Typical hydro-transport pipeline velocities are in the order 5 meters per second. Thus, 2 minutes of shake time is the equivalent of 600 meters of hydro-transport pipeline.)

Settling times were observed and recorded. The time for phase separation ranged from approximately 4 minutes at 2:1 solvent:bitumen ratios to under 2 minutes at 3:1 solvent:bitumen ratios.

It was observed that at the higher 3:1 solvent:bitumen ratio the interphase between the dilute bitumen layer and aqueous layer became ragged, as there was the formation of a rag layer. This phenomenon was witnessed during the table tops tests and has also been observed in the third stage froth settler at Shell Albion Sands facility, which employs a paraffinic solvent process. This rag layer is attributed to asphaltene precipitation caused by a high solvent:bitumen ratio.

The diluted bitumen phase was removed from each of sample containers and tested for BS&W, while the water/solids phase was weighed and analysed for solvent content via a gas chromatograph (GC). All diluted bitumen samples analysed were found to have a BS&W of 0.0%.

The percentage recovery of the bitumen was back calculated as follows:

For a 100 gram sample, there is $.112 \times 100 = 11.2$ grams of bitumen. To this was added 50 ml, or $50 \text{ ml} \times 1 \text{ g/ml} = 50$ grams of water. Thus the starting mass of sample = 150 grams.

Therefore: $150\text{g} - \text{mass of water/solids layer after solvent extraction} = \text{mass of bitumen extracted into the solvent}.$

Specifically, in the 2:1 solvent:bitumen experiments, the mass differential averaged out to 10 grams.

$(10\text{g}/11.2\text{g}) \times 100 = 89.3 \%$ recovery of the asphaltene.

The GC analysis of the water phase showed an average solvent content of 166 mg/ kg.

When converted to a basis of barrels of solvent loss/1000 barrels of bitumen produced (density of bitumen and solvent taken as 975 kg/m³ and 630 kg/m³ respectively) this number equates to 1.28 bbl/1000, which is less than the maximum of 4 bbl/1000bbl as per government regulations.

Although the foregoing invention has been described in some detail by way of illustration and example for purposes of clarity of understanding, it will be readily apparent to those of skill in the art in light of the teachings of this invention that changes and modification may be made thereto without departing from the spirit or scope of the appended claims.

What is claimed is:

1. A method comprising:

a) preparing a slurry having a temperature of about 5°C to about 25°C by mining an oil sand deposit to produce a mined oil sand comprising a heavy oil adhered to inert particles and mixing the mined oil sand with water;

b) mixing the slurry with at least one hydrocarbon solvent to produce a solvent-slurry mixture;

c) agitating the solvent-slurry mixture by transporting the solvent-slurry mixture along a pipeline, to produce an emulsion comprising i) a solution of the heavy oil dissolved in the hydrocarbon solvent ii) an aqueous phase and iii) the inert particles; and

d) separating the phases of the emulsion into a diluted heavy oil fraction comprising the heavy oil and a tailings fraction by applying a phase separation force over a phase separation period;

wherein the heavy oil is separated from the inert particles by dissolving the heavy oil in the hydrocarbon solvent.

2. The method of claim 1 wherein the phase separation force is a G-force of at least 1.

3. The method of claim 1 or 2 wherein the phase separation force is a G-force of between 1 and 4000.

4. The method of any one of claims 1 to 3 wherein the phase separation force is a G-force of between 1 and 1000.

5. The method of any one of claims 1 to 4 wherein the phase separation force is a G-force of between 1 and 10.

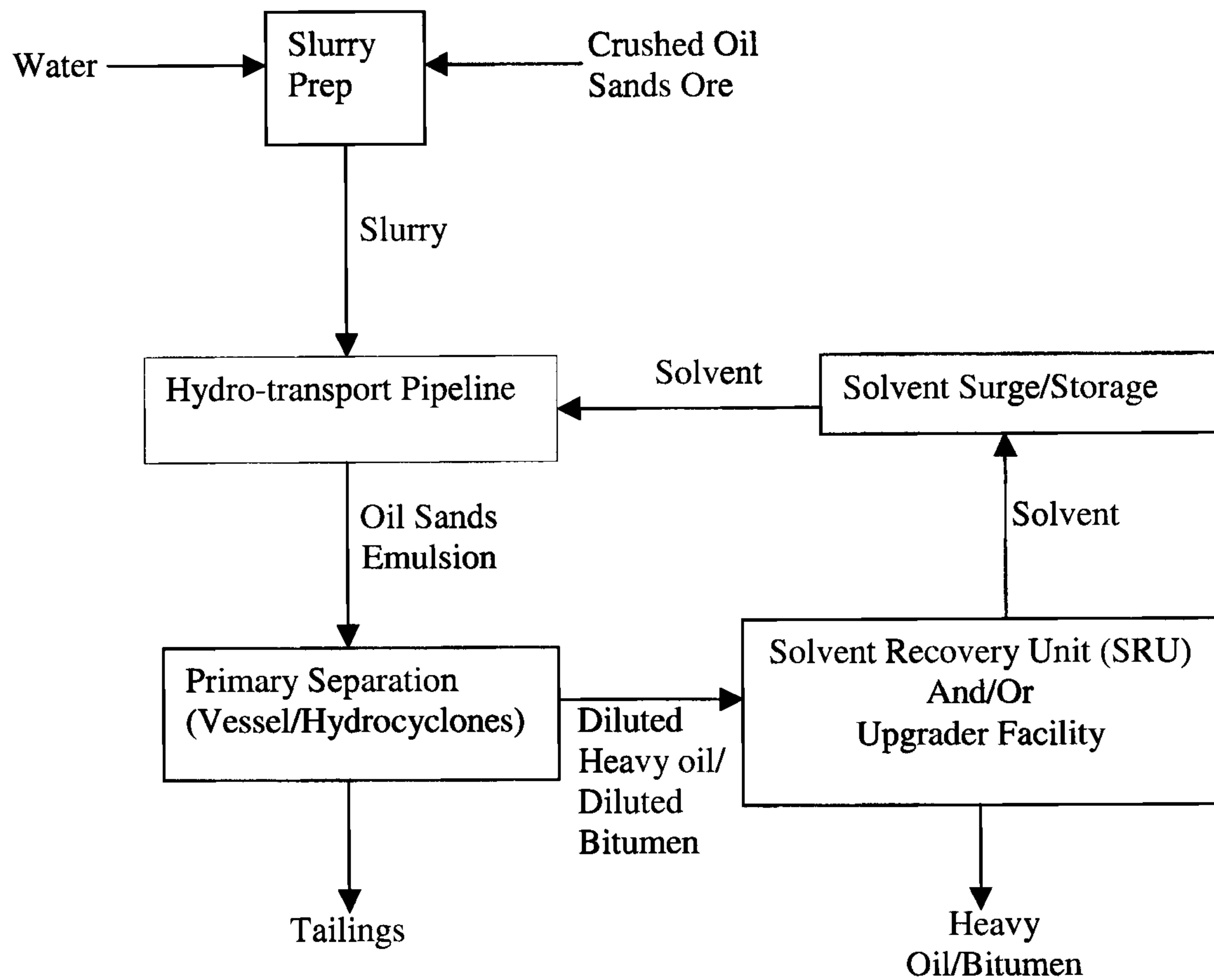
6. The method of any one of claims 1 to 5 wherein the phase separation force is gravity.

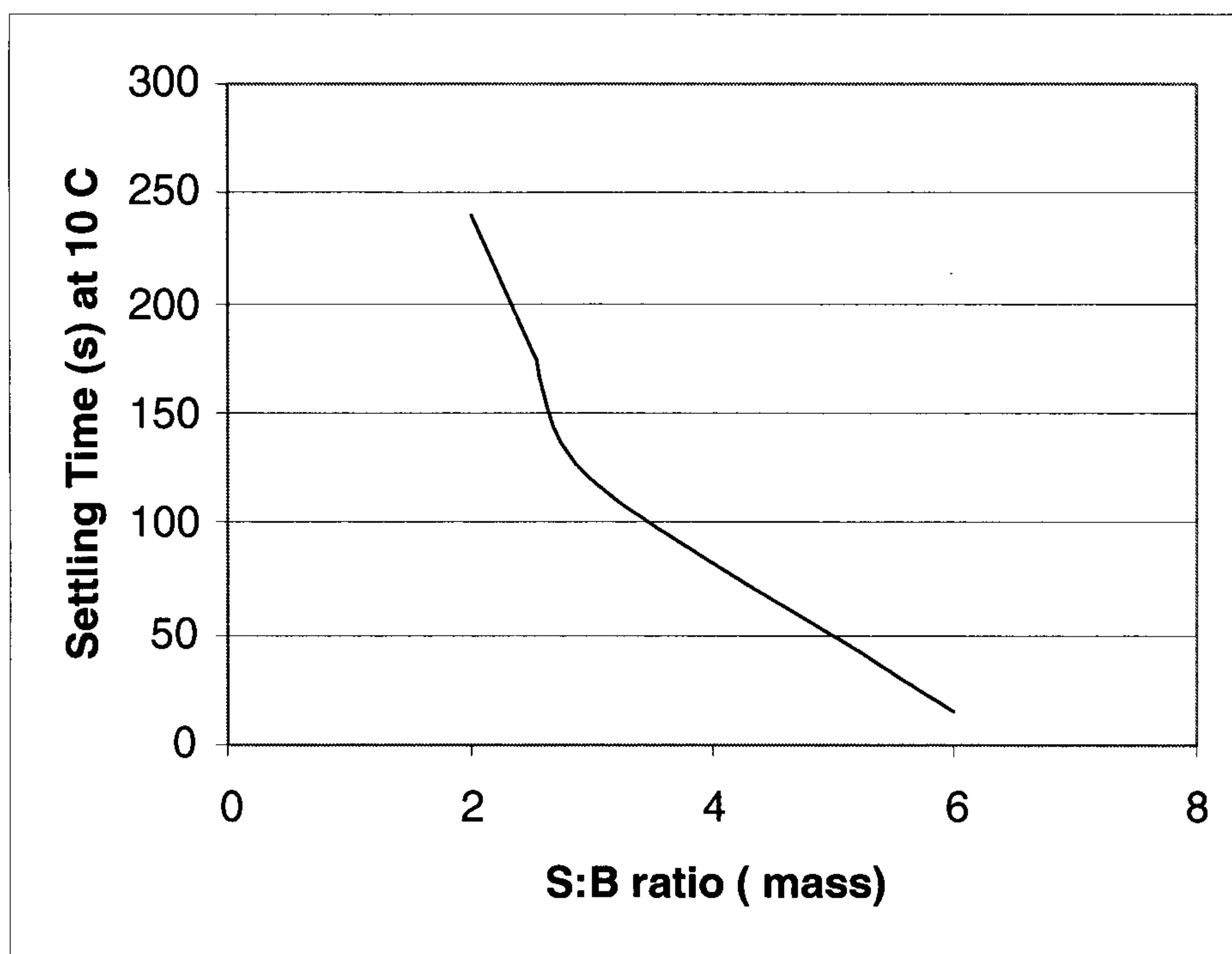
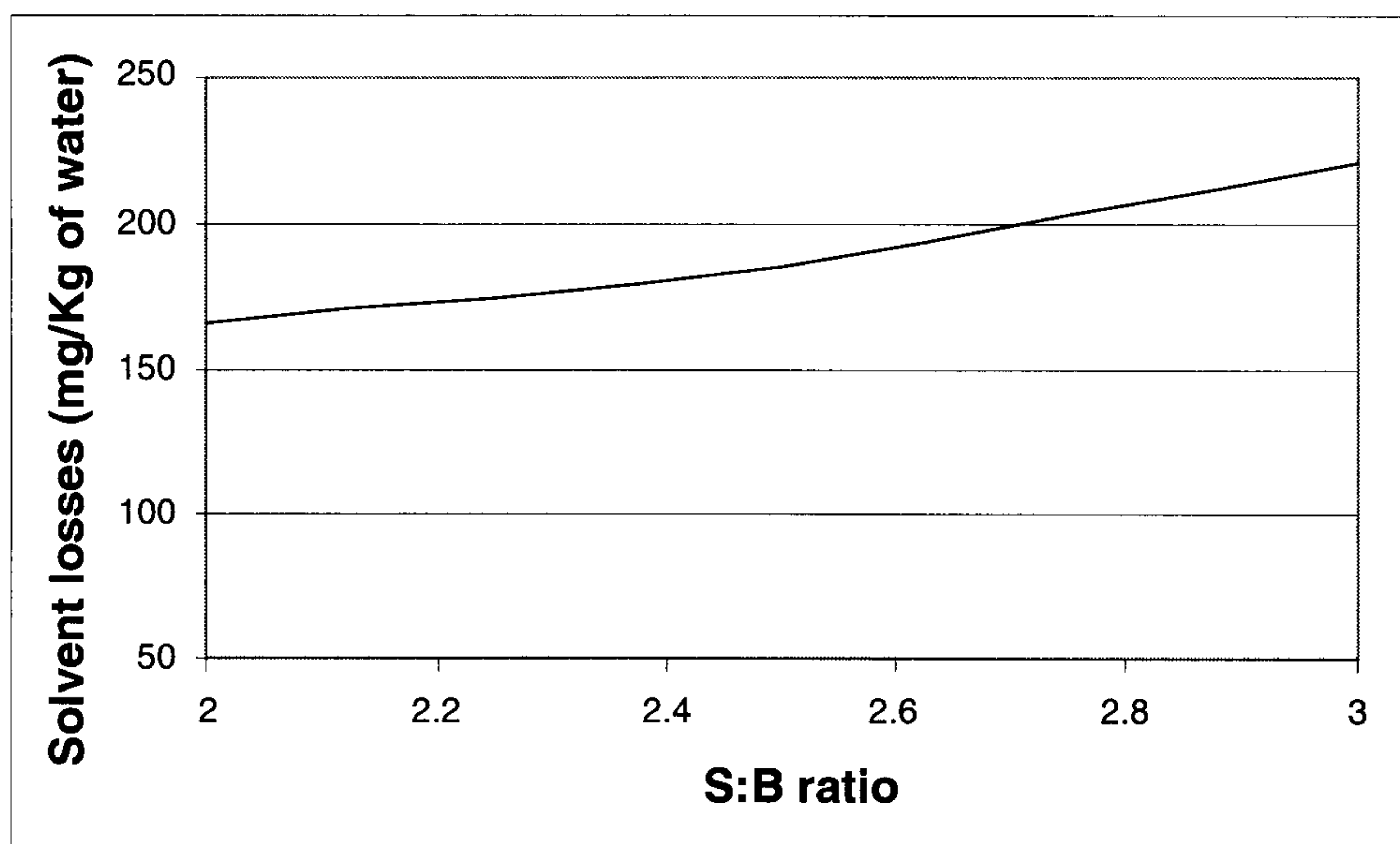
7. The method of any one of claims 1 to 5 wherein the phase separation force is a centrifugal force or a centripetal force.

8. The method of any one of claims 1 to 7 wherein the phase separation period is at least 4 minutes.
9. The method of any one of claims 1 to 7 wherein the phase separation period is less than 4 minutes.
10. The method of any one of claims 1 to 7 wherein the phase separation period is between about 1 to about 4 minutes.
11. The method of any one of claims 1 to 10 wherein the diluted heavy oil fraction is recovered from the emulsion at a primary separation facility.
12. The method of any one of claims 1 or 11 wherein the mixing is provided in the pipeline.
13. The method of any one of claims 1 to 12 wherein the pipeline is a hydrotransport pipeline.
14. The method of any one of claims 1 to 13 wherein the at least one hydrocarbon solvent is a light hydrocarbon solvent.
15. The method of any one of claims 1 to 13 wherein the at least one hydrocarbon solvent is selected from the group consisting of: a branched alkane, an unbranched alkane, a cyclic alkane, and an aromatic hydrocarbon.
16. The method of any one of claims 1 to 13 wherein the at least one hydrocarbon solvent is at least one C₄ to C₁₆ alkane.
17. The method of any one of claims 1 to 13 wherein the at least one hydrocarbon solvent is at least two hydrocarbon solvents selected from the group consisting of: a branched alkane, an unbranched alkane, a cyclic alkane, and an aromatic hydrocarbon.
18. The method of any one of claims 1 to 13 wherein the at least one hydrocarbon solvent is a paraffinic solvent.

19. The method of any one of claims 1 to 13 wherein the at least one hydrocarbon solvent is a naphthenic solvent.
20. The method of any one of claims 1 to 19 wherein the at least one hydrocarbon solvent has a density of less than 0.9 g/mL.
21. The method of any one of claims 1 to 19 wherein the at least one hydrocarbon solvent has a density of between about 0.4 g/mL and about 0.9 g/mL.
22. The method of any one of claims 1 to 19 wherein the at least one hydrocarbon solvent has a density of between about 0.5 g/mL and about 0.8 g/mL.
23. The method of any one of claims 1 to 19 wherein the at least one hydrocarbon solvent has a density of between about 0.6 g/mL and about 0.7 g/mL.
24. The method of any one of claims 1 to 13 wherein the at least one hydrocarbon solvent is selected from the group consisting of: benzene, toluene, xylene and ethyl benzene.
25. The method of any one of claims 1 to 13 wherein the at least one hydrocarbon solvent is selected from the group consisting of: n-pentane, naphtha, Varsol™, paint thinner, Naptha™, paraffinic solvent, reformat and hexane.
26. The method of any one of claims 1 to 25 wherein the emulsion has a temperature from about 5°C to about 25°C.
27. The method of any one of claims 1 to 26 wherein the water has a temperature from about 5°C to about 25°C.
28. The method of any one of claims 1 to 27 wherein the slurry has a density of about 1.1 g/cc to about 1.7 g/cc.

29. The method of any one of claims 1 to 27 wherein the slurry has a density of about 1.3 g/cc to about 1.65 g/cc.
30. The method of any one of claims 1 to 27 wherein the slurry has a density of about 1.4 g/cc to about 1.5 g/cc.
31. The method of any one of claims 1 to 30 wherein the emulsion has a solvent to bitumen ratio of about 1.5:1 by weight to about 3:1 by weight.
32. The method of any one of claims 1 to 30 wherein the emulsion has a solvent to bitumen ratio of about 1.5:1 by weight to about 2.5:1 by weight.
33. The method of any one of claims 1 to 30 wherein the emulsion has a solvent to bitumen ratio of about 2:1 by weight.
34. The method of any one of claims 1 to 33 wherein the agitating has a duration of at least two minutes.
35. The method of any one of claims 11 wherein the primary separation facility is a primary separation vessel.
36. The method of claim 35 wherein the primary separation vessel has a pressure rating greater than the vapour pressure of the hydrocarbon solvent at a maximum operating temperature.
37. The method of claim 35 or 36 wherein the primary separation vessel has a vapour recovery unit.
38. The method of any one of claims 35 to 37 wherein the primary separation vessel has a volume that provides a minimum emulsion residence time of four minutes.
39. The method of any one of claims 11 wherein the primary separation facility is a hydrocyclone facility.

**FIG. 1**

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

