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(54) **Titre :** INJECTION DE CO₂ DANS UN PROCEDE D'EXTRACTION DE BITUME

(54) **Title:** CO₂ INJECTION INTO A BITUMEN EXTRACTION PROCESS

(57) **Abrégé/Abstract:**

A method comprises introducing an oil sand slurry stream to a primary separation cell (PSC) and forming a bitumen froth, a middlings stream, and a coarse sand tailings stream (CST); introducing the middlings stream to a flotation process and forming a recycle froth and a flotation tailings stream; and introducing CO₂ into one or more of: i) the PSC, beneath a froth layer; ii) the middlings stream; and iii) the flotation process, for increasing bitumen recovery, sequestering carbon dioxide in the CST and/or the flotation tailings stream, increasing fines capture in the CST, or a combination thereof.

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ABSTRACT

A method comprises introducing an oil sand slurry stream to a primary separation cell (PSC) and forming a bitumen froth, a middlings stream, and a coarse sand tailings stream (CST); introducing the middlings stream to a flotation process and forming a recycle froth and a flotation tailings stream; and introducing CO₂ into one or more of: i) the PSC, beneath a froth layer; ii) the middlings stream; and iii) the flotation process, for increasing bitumen recovery, sequestering carbon dioxide in the CST and/or the flotation tailings stream, increasing fines capture in the CST, or a combination thereof.

CO₂ INJECTION INTO A BITUMEN EXTRACTION PROCESS

BACKGROUND

Field of Disclosure

[0001] The disclosure relates generally to the field of oil sand processing, and more particularly to water-based extraction.

Description of Related Art

[0002] 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.

[0003] 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 costs of hydrocarbons increase, the less accessible sources become more economically attractive.

[0004] Recently, the harvesting of oil sand to remove heavy oil has become more economical. Hydrocarbon removal from oil sand may be performed by several techniques. For example, a well can be drilled to an oil sand reservoir and steam, hot air, 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. In another technique, strip or surface

mining may be performed to access the oil sand, which can be treated with water, steam or solvents to extract the heavy oil.

[0005] Oil sand extraction processes are used to liberate and separate bitumen from oil sand so that the bitumen can be further processed to produce synthetic crude oil or mixed with diluent to form “dilbit” and be transported to a refinery plant. Numerous oil sand extraction processes have been developed and commercialized, many of which involve the use of water as a processing medium. Where the oil sand is treated with water, the technique may be referred to as water-based extraction (WBE) or as a water-based oil sand extraction process. WBE is a commonly used process to extract bitumen from mined oil sand.

[0006] One WBE process is the Clark hot water extraction process (the “Clark Process”). This process typically requires that mined oil sand be conditioned for extraction by being crushed to a desired lump size and then combined with hot water and perhaps other agents to form a conditioned slurry of water and crushed oil sand. In the Clark Process, an amount of sodium hydroxide (caustic) may be added to the slurry to increase the slurry pH, which enhances the liberation and separation of bitumen from the oil sand. Other WBE processes may use other temperatures and may include other conditioning agents, which are added to the oil sand slurry, or may operate without conditioning agents. This slurry is first processed in a Primary Separation Cell (PSC), also known as a Primary Separation Vessel (PSV), to extract the bitumen from the slurry.

[0007] In one WBE process, a water and oil sand slurry is separated into three major streams in the PSC: bitumen froth, middlings, and a PSC underflow (also referred to as coarse sand tailings (CST)).

[0008] Regardless of the type of WBE process employed, the process will typically result in the production of a bitumen froth that requires treatment with a solvent. For example, in the Clark Process, a bitumen froth stream comprises bitumen, solids, and water. Certain processes use naphtha to dilute bitumen froth before separating the product bitumen by centrifugation. These processes are called naphtha froth treatment (NFT) processes. Other

processes use a paraffinic solvent, and are called paraffinic froth treatment (PFT) processes, to produce pipelineable bitumen with low levels of solids and water. In the PFT process, a paraffinic solvent (for example, a mixture of iso-pentane and n-pentane) is used to dilute the froth before separating the product, diluted bitumen, by gravity. A portion of the asphaltenes in the bitumen is also rejected by design in the PFT process and this rejection is used to achieve reduced solids and water levels. In both the NFT and the PFT processes, the diluted tailings (comprising water, solids and some hydrocarbon) are separated from the diluted product bitumen.

[0009] Solvent is typically recovered from the diluted product bitumen component before the bitumen is delivered to a refining facility for further processing.

[0010] The PFT process may comprise at least three units: Froth Separation Unit (FSU), Solvent Recovery Unit (SRU) and Tailings Solvent Recovery Unit (TSRU). Mixing of the solvent with the feed bitumen froth may be carried out counter-currently in two stages in separate froth separation units. The bitumen froth comprises bitumen, water, and solids. A typical composition of bitumen froth is about 60 wt. % bitumen, 30 wt. % water, and 10 wt. % solids. The paraffinic solvent is used to dilute the froth before separating the product bitumen by gravity. The foregoing is only an example of a PFT process and the values are provided by way of example only. An example of a PFT process is described in Canadian Patent No. 2,587,166 to Sury.

[0011] From the PSC, the middlings, which may comprise bitumen and about 10-30 wt. % solids, or about 20-25 wt. % solids, based on the total wt. % of the middlings, is withdrawn and sent to the flotation cells to further recover bitumen. The middlings are processed by bubbling air through the slurry and creating a bitumen froth, which is recycled back to the PSC. Flotation tailings (FT) from the flotation cells, comprising mostly solids and water, are sent for further treatment or disposed in an external tailings area (ETA).

SUMMARY

[0012] A method comprises introducing an oil sand slurry stream to a primary separation cell (PSC) and forming a bitumen froth, a middlings stream, and a coarse sand tailings stream (CST); introducing the middlings stream to a flotation process and forming a recycle froth and a flotation tailings stream; and introducing CO₂ into one or more of: i) the PSC, beneath a froth layer; ii) the middlings stream; and iii) the flotation process, for increasing bitumen recovery, sequestering carbon dioxide in the CST and/or the flotation tailings stream, increasing fines capture in the CST, or a combination thereof.

[0013] The foregoing has broadly outlined the features of the present disclosure so that the detailed description that follows may be better understood. Additional features will also be described herein.

BRIEF DESCRIPTION OF THE DRAWING

[0014] These and other features, aspects and advantages of the disclosure will become apparent from the following description, appending claims and the accompanying drawing, which is briefly described below.

[0015] Fig. 1 is a flow diagram of an oil sand slurry treatment process including CO₂ injection.

[0016] It should be noted that the figure is merely an example and no limitations on the scope of the present disclosure is intended thereby. Further, the figure is generally not drawn to scale, but is drafted for purposes of convenience and clarity in illustrating various aspects of the disclosure.

DETAILED DESCRIPTION

[0017] 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.

[0018] 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.

[0019] Throughout this disclosure, where a range is used, any number between or inclusive of the range is implied.

[0020] 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 sand. However, the techniques described are not limited to heavy oils but may also be used with any number of other reservoirs to improve gravity drainage of liquids. Hydrocarbon compounds may be aliphatic or aromatic, and may be straight chained, branched, or partially or fully cyclic.

[0021] “Bitumen” is a naturally occurring heavy oil material. Generally, it is the hydrocarbon component found in oil sand. 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.) % 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 in excess of 7 wt. %), the weight % based upon total weight of the bitumen.

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.

[0022] “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/m^3) or 0.920 grams per centimeter cubed (g/cm^3)) and 10.0° API (density of 1,000 kg/m^3 or 1 g/cm^3). An extra heavy oil, in general, has an API gravity of less than 10.0° API (density greater than 1,000 kg/m^3 or 1 g/cm^3). For example, a source of heavy oil includes oil sand or bituminous sand, which is a combination of clay, sand, water and bitumen.

[0023] “Fine particles” or “fines” are generally defined as those solids having a size of less than 44 microns (μm), as determined by laser diffraction particle size measurement.

[0024] “Coarse particles” are generally defined as those solids having a size of greater than 44 microns (μm).

[0025] The term “solvent” as used in the present disclosure should be understood to mean either a single solvent, or a combination of solvents.

[0026] 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 who review this disclosure 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.

[0027] 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.

[0028] The term “paraffinic solvent” (also known as aliphatic) as used herein means solvents comprising normal paraffins, isoparaffins or blends thereof in amounts greater than 50 wt. %. Presence of other components such as olefins, aromatics or naphthenes may counteract the function of the paraffinic solvent and hence may be present in an amount of only 1 to 20 wt. % combined, for instance no more than 3 wt. %. The paraffinic solvent may be a C₄ to C₂₀ or C₄ to C₆ paraffinic hydrocarbon solvent or a combination of iso and normal components thereof. The paraffinic solvent may comprise pentane, iso-pentane, or a combination thereof. The paraffinic solvent may comprise about 60 wt. % pentane and about 40 wt. % iso-pentane, with none or less than 20 wt. % of the counteracting components referred above.

[0029] One method may comprise introducing an oil sand slurry stream to a primary separation cell (PSC) and forming a bitumen froth, a middlings stream, and a coarse sand tailings stream (CST); introducing the middlings stream to a flotation process and forming a recycle froth and a flotation tailings stream; and introducing CO₂ into one or more of: i) the PSC, beneath a froth layer; ii) the middlings stream; and iii) the flotation process, for increasing bitumen recovery, sequestering carbon dioxide in the CST and/or the flotation tailings stream, increasing fines capture in the CST, or a combination thereof.

[0030] The oil sand slurry stream may be any suitable oil sand slurry stream and may stem from mined oil sand. For example, the oil sand slurry stream may comprise 7 to 16 wt.

% bitumen, 1 to 7 wt. % water, and 77 to 92 wt. % solids; or 10 to 12.5 wt. % bitumen, 2.5 to 6 wt. % water, and 81.5 to 87.5 wt. % solids.

[0031] The PSC may be any suitable gravity separation vessel for extracting bitumen from the oil sand slurry stream. The PSC may generally comprise a conical section (“PSC” cone) beneath a cylindrical section.

[0032] The flotation process may be any suitable flotation process and may include primary and secondary flotation cells. The flotation process may form a recycle froth, which may be recycled to the PSC.

[0033] By “increasing bitumen recovery”, it is meant increasing a weight percentage of bitumen that is extracted from the oil sand slurry stream, rather than ending up in tailings.

[0034] By “increasing fines capture in the CST”, it is meant increasing a weight percentage of fines that is removed from the oil sand slurry, rather than ending up in the bitumen froth or in the middlings.

[0035] By “sequestering carbon dioxide in the CST and/or the flotation tailings stream”, it is meant capturing carbon dioxide within the CST and/or the flotation tailings stream, and converting to bicarbonate or carbonate species as opposed to having it released to the atmosphere.

[0036] Injecting CO₂ (carbon dioxide) into the PSC may increase bitumen uplift, increase fines capture from the CST on the beach or in the pond and sequester CO₂ in the tailings. The injection of CO₂ may provide an upward superficial velocity which may enable bitumen lost to the PSC cone to be recovered. The slight drop in pH in the PSC due to CO₂ addition may create an environment more conducive to bitumen/bubble attachment by reducing the zeta potential and therefore enhancing hydrophobic interactions between gas bubbles and bitumen, thus enhancing bitumen recovery. In addition, CO₂ may lower divalent ions (e.g. Mg²⁺, Ca²⁺) content and increase bicarbonate (HCO₃⁻) content, thereby further enhancing bitumen recovery. For fines capture, CO₂ may act as a coagulant in the formation

of non-segregating tailings, and may potentially enhance beach fines capture. CST may provide a greater quantity of tailings for carbon dioxide capture compared to flotation tailings. The volumetric flow of CO₂ into the PSC may provide an upward velocity to capture bitumen short circuited to the PSC cone. In addition, bubble/bitumen contact may add buoyancy to the bitumen droplets and provide an opportunity for recovery. Whilst gas addition at the top of the PSC may be discouraged due to a risk of destabilizing the froth and increasing entrainment, CO₂ addition at the bottom of the PSC is less likely to destabilize the PSC.

[0037] Injecting CO₂ into flotation cells during the flotation process may enhance bitumen recovery and may facilitate the sequestration process of CO₂ using minerals. Any suitable diluted stream of CO₂ (for instance comprising water, nitrogen, and 4 - 10 mol. % CO₂) from a flue gas stream, from boilers or upgrading facilities, or concentrated via available commercial capture technologies may be used for the injection application. The CO₂ injection may be at operating conditions of the flotation cells, e.g. ambient pressure and a temperature of about 37°C. CO₂ injection into an aqueous oil sand slurry may decrease the pH. Bitumen droplets may be more effectively aerated at a lower pH in the flotation process due to more hydrophobic interaction between bitumen and bubbles. Potential benefits of injection CO₂ into the flotation process may include:

- a. higher bitumen recovery due to more effective flotation, lower divalent ions (e.g. Mg²⁺, Ca²⁺) content and higher bicarbonate (HCO³⁻) content;
- b. higher froth quality at lower pH due to precipitation of fines (clay/silicate);
- c. accelerated formation of non-segregating fines in the tailings; and
- d. CO₂ may act as a coagulant, thereby improving thickener operation when treating flotation tailing with lower pH.

[0038] The CO₂ may be introduced into the PSC, beneath a froth layer. The CO₂ may be introduced into a cone portion of the PSC. The CO₂ may be introduced into the PSC as part of a froth underwash stream, as part of a PSC dilution water stream, or as part of a flush

water stream. The CO₂ may be combined with a portion of the flotation tailings stream prior to being introduced into the PSC. The CO₂ may be introduced into the PSC via a gas sparger to assist a bubble dispersion and increase a bubble surface area. The method may further comprise adding an offset water stream to the PSC to maintain the slurry properties (density, viscosity) that might have been changed due to the CO₂ introduction, including but not limited to settling fines, recovering bitumen, sequestration of CO₂. The method may further comprise introducing a surfactant into the PSC to assist an effect of the CO₂ introduction.

[0039] The CO₂ may be introduced into the middlings stream or into the flotation process. The CO₂ may be introduced into a primary flotation cell or into a secondary flotation cell of the flotation process.

[0040] The CO₂ may stem from a flue gas. The CO₂ may stem from a boiler, a bitumen upgrading facility, a water recovery process, a carbon capture process, or a combination thereof. A bubble size of the introduced CO₂ may be controlled by mechanical or chemical means. The chemical means may comprise adding a frother. The frother may be any suitable organic compound, such as ethanol and methanol, that can facilitate future conditioning and processing of the froth.

[0041] The method may further comprise adding a calcium-based additive to the CST, the flotation tailings stream, or a downstream tailings stream, to assist bicarbonate formation. The calcium-based additive may comprise lime, quicklime, slaked lime, hydrated lime, gypsum, or a combination thereof. The method may further comprise measuring a fines content in the oil sand slurry stream; and introducing the CO₂ in an amount based on the measured fines content. The measuring of the fines content may be performed using manual sampling methods or through the use of an online fines analyzer. The online fines analyzer may be any suitable online fines analyzer, for instance it may be a K40 analyzer.

[0042] The method may further comprise measuring a fines content in the oil sand slurry stream; and selectively introducing the CO₂, based on the measured fines content, into the one or more of i) the PSC beneath the froth layer, ii) the middlings stream, and iii) the

flotation process. Where the measured fines content is below a predetermined fines content, the CO₂ introduction may be prior to the flotation process and wherein where the measured fines content is above a predetermined fines content, the CO₂ introduction may be into the flotation process. The predetermined fines content may be less than 50% of a selected control case value for fines content.

[0043] The method may further comprise adding a gaseous process additive to decrease a pH of the oil sand slurry stream. The gaseous process additive may comprise a non-oxidizing acid.

[0044] Fig. 1 is a flow diagram of an oil sand slurry treatment process including CO₂ injection in three locations. One or more of such injection locations may be used.

[0045] With reference to Figure 1, an oil sand slurry stream (202) may be introduced into a primary separation cell (PSC) (204) forming a bitumen froth (206), a middlings stream (208), and a coarse sand tailings stream (CST) (210). The middlings stream (208) may be introduced into a flotation process, illustrated by flotations cells (212). The flotation cells may form a recycle froth (214) and a flotation tailings stream (216). CO₂ (218, 220, 224) may be introduced into one or more of: i) the PSC (204), beneath a froth layer (illustrated with stream 218); ii) the middlings stream (208) (illustrated with stream 220); and the flotation process (illustrated with stream 224), for increasing bitumen recovery, sequestering carbon dioxide in the CST and/or the flotation tailings, increasing fines capture in the CST, or a combination thereof.

[0046] The CO₂ partial pressure (e.g., 100 - 1000 kPa) or location may be selected based on ore type. For instance, for low fines ores, CO₂ injection may be into the froth underwash, the dilution water, or the middlings to enhance bitumen and bubble attachment. For instance, for high fines ores, CO₂ injection may be during a flotation step, e.g. into the middlings or the flotation cells to facilitate solids and bitumen separation, in cases where fines can be highly concentrated in the middlings layer.

[0047] 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. The scope of the claims should not be limited by particular embodiments set forth herein, but should be construed in a manner consistent with the specification as a whole.

CLAIMS:

1. A method comprising:
 - a) introducing an oil sand slurry stream to a primary separation cell (PSC) and forming a bitumen froth, a middlings stream, and a coarse sand tailings stream (CST);
 - b) introducing the middlings stream to a flotation process and forming a recycle froth and a flotation tailings stream;
 - c) introducing CO₂ into one or more of:
 - i) the PSC, beneath a froth layer;
 - ii) the middlings stream; and
 - iii) the flotation process,for increasing bitumen recovery, sequestering carbon dioxide in the CST and/or the flotation tailings stream, increasing fines capture in the CST, or a combination thereof; and
 - d) introducing a surfactant or frother into the PSC to assist an effect of the CO₂ introduction.
2. The method of claim 1, wherein the CO₂ is introduced into the PSC, beneath a froth layer.
3. The method of claim 2, wherein the CO₂ is introduced into a cone portion of the PSC.
4. The method of claim 2, wherein the CO₂ is introduced into the PSC as part of a froth underwash stream.
5. The method of claim 2, wherein the CO₂ is introduced into the PSC as part of a PSC dilution water stream.

6. The method of claim 2, wherein the CO₂ is combined with a portion of the flotation tailings stream prior to being introduced into the PSC.
7. The method of claim 2, wherein the CO₂ is introduced into the PSC as part of a flush water stream.
8. The method of claim 2, wherein the CO₂ is introduced into the PSC via a gas sparger to assist a bubble dispersion and increase a bubble surface area.
9. The method of claim 2, further comprising adding an offset water stream to the PSC to offset viscosity or density changes caused by the CO₂ introduction.
10. The method of claim 1, wherein the CO₂ is introduced into the middlings stream.
11. The method of claim 1, wherein the CO₂ is introduced into the flotation process.
12. The method of claim 11, wherein the CO₂ is introduced into a primary flotation cell of the flotation process.
13. The method of claim 11, wherein the CO₂ is introduced into a secondary flotation cell of the flotation process.
14. The method of any one of claims 1 to 13, wherein the CO₂ stems from a flue gas.
15. The method of claim 14, wherein the CO₂ stems from a boiler, a bitumen upgrading facility, a water recovery process, a carbon capture process, or a combination thereof.
16. The method of any one of claims 1 to 15, wherein a bubble size of the introduced CO₂ is controlled by mechanical or chemical means.

17. The method of any one of claims 1 to 16, further comprising adding a calcium-based additive to the CST, the flotation tailings stream, or a downstream tailings stream, to assist bicarbonate formation.
18. The method of claim 17, wherein the calcium-based additive comprises lime, quicklime, slaked lime, hydrated lime, gypsum, or a combination thereof.
19. The method of claim 17, further comprising:
measuring a fines content in the oil sand slurry stream; and
introducing the CO₂ in an amount based on the measured fines content.
20. The method of claim 19, wherein the measuring the fines content is performed using an online fines analyzer.
21. The method of claim 20, wherein the online fines analyzer is a K40 analyzer.
22. The method of claim 1, further comprising:
measuring a fines content in the oil sand slurry stream; and
selectively introducing the CO₂, based on the measured fines content, into the one or more of i) the PSC beneath the froth layer, ii) the middlings stream, and iii) the flotation process.
23. The method of claim 11, wherein where the measured fines content is below a predetermined fines content, the CO₂ introduction is prior to the flotation process and wherein where the measured fines content is above a predetermined fines content, the CO₂ introduction is into the flotation process.
24. The method of claim 23, wherein the predetermined fines content is less than 50% of a selected control case value for fines content.

25. The method of any one of claims 1 to 24, further comprising adding a gaseous process additive to decrease a pH of the oil sand slurry stream.
26. The method of claim 25, wherein the gaseous process additive comprises a non-oxidizing acid.
27. The method of any one of claims 1 to 26, wherein the oil sand slurry stream stems from mined oil sand.
28. The method of any one of claims 1 to 27, wherein the oil sand slurry stream comprises 7 to 16 wt. % bitumen, 1 to 7 wt. % water, and 77 to 92 wt. % solids.
29. The method of any one of claims 1 to 28, wherein the oil sand slurry stream comprises 10 to 12.5 wt. % bitumen, 2.5 to 6 wt. % water, and 81.5 to 87.5 wt. % solids.

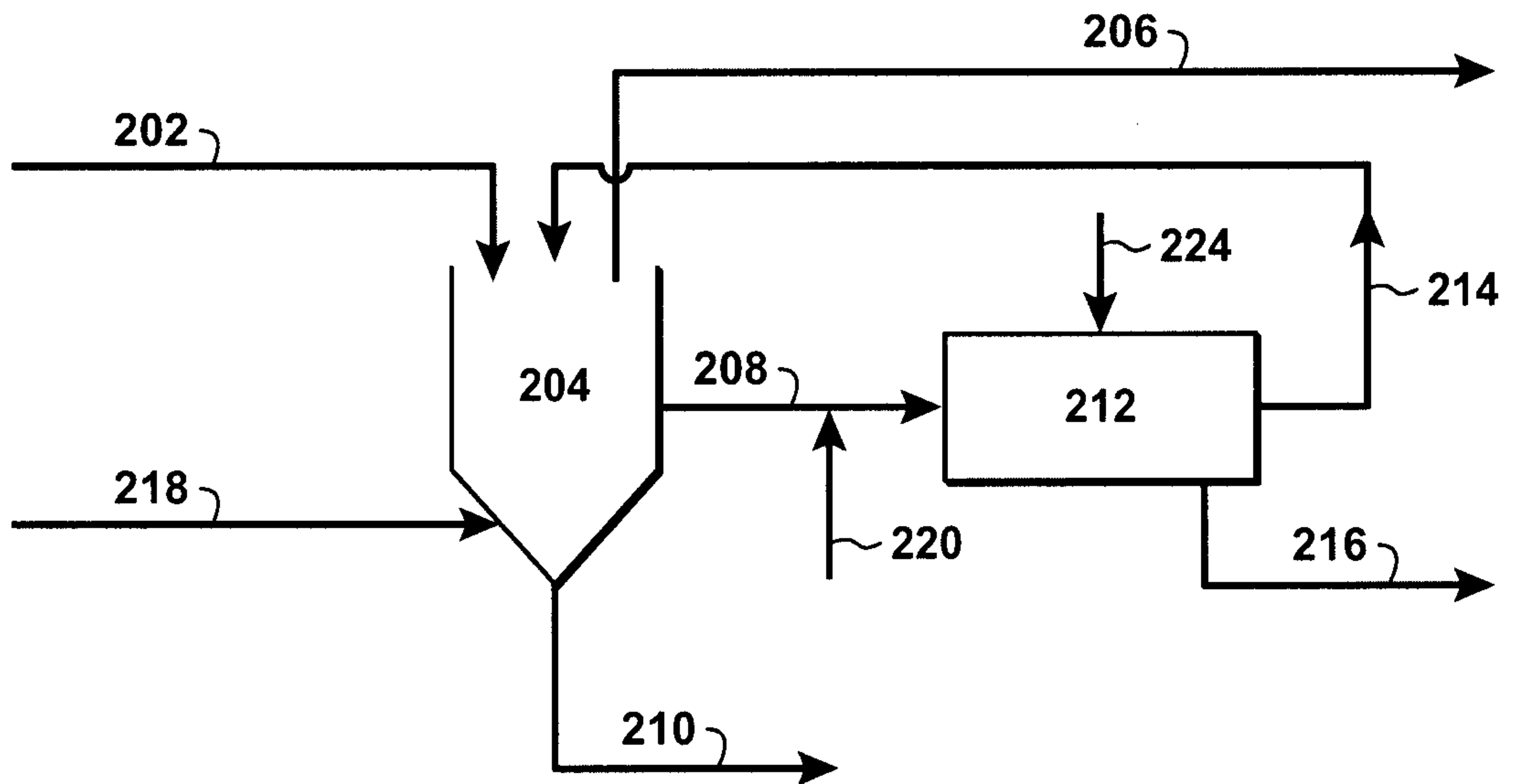


FIG. 1