

(51) International Patent Classification:
C10G 1/04 (2006.01)(21) International Application Number:
PCT/US2012/024938(22) International Filing Date:
14 February 2012 (14.02.2012)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
13/044,044 9 March 2011 (09.03.2011) US(71) Applicant (for all designated States except US): **LINDE AKTIENGESELLSCHAFT** [DE/DE]; Klosterhofstr. 1, 80331 Munich (DE).

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(81) Designated States (unless otherwise indicated, for every kind of national protection available): AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IS, JP, KE, KG, KM, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LT, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States (unless otherwise indicated, for every kind of regional protection available): ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, ML, MR, NE, SN, TD, TG).

Published:

— with international search report (Art. 21(3))

(54) Title: METHOD FOR IMPROVING OIL SANDS HOT WATER EXTRACTION PROCESS

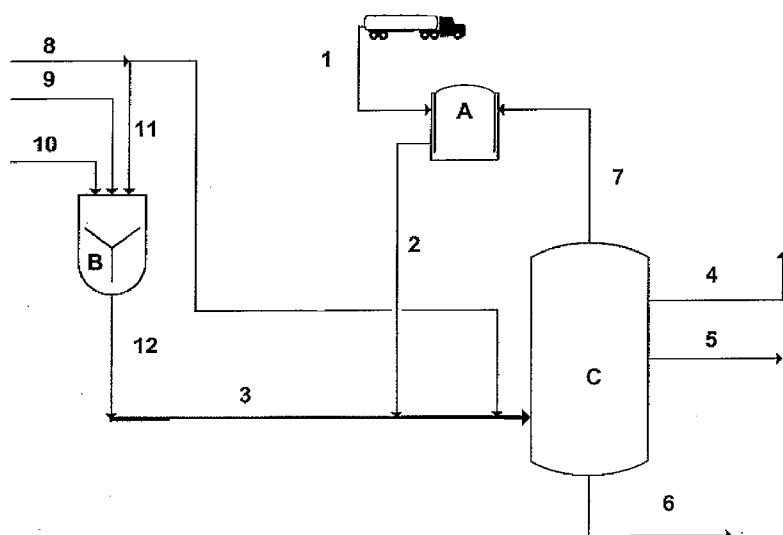


FIGURE 1

(57) Abstract: A method for increasing the bitumen extraction efficiency in the hot water oil sands extraction process. A volume of gaseous carbon dioxide is added into the oil sands slurry that is being transported through a hydrotransport pipeline from the oil sands mining site to the bitumen extraction plant at a position where the oil sands has been conditioned to a desired degree. Carbon dioxide is injected into the slurry under elevated pressure through a gas distribution device while the hydraulic pressure in the pipeline is maintained at an elevated pressure. After the carbon dioxide-bearing oil sands slurry is fed into the separation vessel, a part of the carbon dioxide is recovered for reinjection.

METHOD FOR IMPROVING OIL SANDS HOT WATER EXTRACTION PROCESS

BACKGROUND OF THE INVENTION

[0001] The present invention relates to a process for adding carbon dioxide in a hydrotransport pipeline through which oil sands slurry is transported to an extraction plant in order to improve bitumen recovery efficiency.

[0002] Hot water extraction process is the most frequently employed technique to recover bitumen from surface mined oil sands. Due to the high capacity and low operating cost of modern hot water extraction process for oil sands and other mined oil bearing formations, other alternative processes are not likely to replace this process in the near future. In a conventional hot water extraction process, before bitumen is extracted in a separation vessel, a mixture of oil sand, hot process water, and extraction additive, normally caustic reagent such as sodium hydroxide or sodium carbonate, is conditioned in a large tumbler or drum by intense mechanical agitation for a predetermined period to achieve a desired separation degree of bitumen from sand grains and entraining of air bubbles in the slurry. This modern hot water extraction process, which is developed from the conventional hot water process, transports oil sand, hot process water and extraction additives to a separation vessel in a pipeline wherein conditioning of oil sand is achieved during transportation. This method, called hydrotransport, is one of the most important developments in the oil sands surface mining industry since it greatly increases treatment capacity of the oil sands extraction plant and reduces energy cost.

[0003] US Patent No. 5,264,118 describes a pipeline conditioning process for mined oil sands wherein oil sands is transported with hot water and sodium hydroxide via a pipeline of sufficient length. During the conditioning process, with assistance of sodium hydroxide, bitumen is liberated from sand grains and

entrained air facilitates subsequent aeration of the bitumen. The conditioned oil sands slurry is fed to a gravity separation vessel, known as primary separation vessel (PSV), to settle into three layers, bitumen froth, middlings, and sand under quiescent conditions. The middlings, which is normally processed in a secondary separation vessel, is a mixture of buoyant bitumen, clay and water. In one embodiment of that invention achieving more 90% total bitumen recovery efficiency, the pipeline has a length of 2.5 kilometers to achieve a desired extraction efficiency for a mixture of 50 to 70% by weight of oil sands, 50 to 30% by weight of hot water, and less than 0.05% by weight of sodium hydroxide at a temperature between 40 °C to 70 °C. The residence time of oil sands slurry in the pipeline is about 14 minutes.

[0004] It is believed that bitumen flecks tend to coalesce and attach or coat to the air bubbles entrained in the slurry. Because the amount of the entrained air is an important factor for oil sands conditioning in the hydrotransport pipeline, a more effective method of adding air into oil sands slurry can significantly improve the overall bitumen extraction efficiency. A device, cyclofeeder, described in Canadian Patent No. 2,029,795 and US Patent No. 5,039,227, can simultaneously entrain air into the slurry when it is mixing oil sands with hot water. In US Patent No. 6,007,708, the aeration effects by gas bubbles are enhanced by injecting compressed air in the hydrotransport pipeline to improve the bitumen extraction efficiency at a relatively low conditioning temperature. The drawback of this process is that the extracted bitumen contains relatively high concentration of impurities due to bitumen's high viscosity at low temperature and incomplete separation of bitumen from sand grains. The volume ratio of air to slurry can be up to 2.5:1 and the overall bitumen recovery efficiency can be as high as 98%. Another example to explore the separation and floatation effects of gas bubbling is described in Canadian Patent No. 2,703,835, in which the oil sands and hot water mixture is treated in a closed vessel by cyclic compression and decompression of compressed air or carbon dioxide in the vessel. This method can achieve more than 90% bitumen extraction

efficiency for tar sands or oil sands from different countries without the assistant of caustic reagent and does not generate middlings. The major drawback of this method is that the extraction capacity of a device is limited by the vessel size due to the high construction cost of a large pressure vessel. Also, International Patent Application No. WO 2005/123608A1 teaches a method of adding hydrogen peroxide into a conditioned mixture of oil sands and hot water. The oxygen bubbles generated through decomposition of hydrogen peroxide may accelerate separation and floatation of bitumen. An obvious drawback of this process is that the high purchasing price of hydrogen peroxide makes this process less competitive. Also, oxygen, which is not preferred in the subsequent bitumen upgrading processes, may have been added into bitumen structures.

[0005] Caustic reagent is normally required to improve the conditioning effects in the hot water extraction process. However, addition of caustic reagent such as sodium hydroxide has many drawbacks. The major problem is that caustic reagent will cause emulsification of released bitumen in water and suspension of fine particles in the aqueous phase. Those effects greatly reduce the overall bitumen extraction efficiency and cause serious environmental problems when the process water is being disposed.

[0006] Another problem is generation of large amount of middlings in the separation vessel. Although most bitumen contained in the middlings and tailings can be recovered in the subsequent extraction processes, improving the primary separation vessel's froth production and quality is the most effective way to reduce the overall operating cost. Canadian Patent 2,004,352 has addressed these problems by replacing the caustic reagent by kerosene and methyl-isobutyl carbinol. This method also has a problem of high operating cost due to usage of large amount of chemicals. In order to treat the process water from the hot water extraction process that contains suspended solids and emulsified bitumen at a high

pH level by the caustic reagent, Canadian Patent 1,022,098 discloses a method to break the emulsion to recover additional bitumen and accelerate precipitation of the suspended solids through neutralizing the process water by addition of inorganic acids and carbon dioxide. It has been recognized that neutralizing the process water to pH at around 7 by an inorganic acid is not sufficient for emulsion breaking. The purpose of utilizing inorganic acid to adjust water pH is to facilitate the emulsion breaking effect of carbon dioxide since carbon dioxide is not a strong acid for pH adjustment. But the addition of inorganic acid generates permanent unwanted salt in the process water and limits reuse of the process water.

[0007] It is noticed that after bitumen is separated from sand grains and bitumen droplets are formed with the help of the caustic reagent, the basic condition is not necessarily to be maintained in the separation vessel for formation of froth. On the contrary, the caustic condition can cause emulsification of bitumen in hot water and generate large amount of middlings. De-emulsification of the emulsion, such as reducing pH of the process water or adding flocculent, can improve the total recovery ratio of bitumen in the primary separation vessel. Since carbon dioxide is a good reagent to neutralize process water, using carbon dioxide to adjust oil sands slurry's pH level is a practical measure. To achieve the emulsion breaking effect, a lower pH value by dissolving more carbon dioxide under elevated pressure may be required. In addition, since noticeable amount of carbon dioxide is dissolved in bitumen under elevated pressure, pressure drop in the primary separation vessel can significantly increase bitumen's buoyancy through expansion of the bitumen droplets. Also, reduction of emulsified bitumen in water and increase of bitumen's buoyancy can prevent generation of large amount of middlings.

[0008] So the operating costs for middlings treatment and subsequent process water treatment can be reduced. Compared to adjusting water pH using assistant inorganic acid, which is used in other methods because carbon dioxide is not

sufficient for pH adjustment in a non pressure vessel or a low pressure vessel, using carbon dioxide will not permanently increase the water salt concentration since the product of carbon dioxide and sodium hydroxide is sodium carbonate, which is also used as a caustic reagent for oil sands extraction in the hot water extraction process. However, pressurizing the primary separation vessel in a larger oil sands extraction plant is not practical because of the high construction cost of a large pressure vessel. Injecting carbon dioxide in the hydrotransport pipeline is a more practical method for adjusting the oil sands slurry's pH.

SUMMARY OF THE INVENTION

[0009] A method for recovering bitumen comprising adding carbon dioxide to a pipeline containing an oil-bearing formation being transported is disclosed.

[0010] The invention aims to improve the bitumen recovery efficiency in the primary separation vessel by simultaneous improvement of the aeration effect and reduction of the bitumen emulsification degree. This invention can be applied, but is not limited to, improving the oil extraction of oil sands and other oil bearing formation in a hot water extraction process. The same method can be applied to remediation of contaminated soil, treatment of waste water, and mine floatation in order to improve treatment efficiency.

[0011] In one embodiment of the invention, carbon dioxide is injected into the hydrotransport pipeline, through which oil sands slurry is conditioned when being transported from a mining site to an extraction plant, at a position where the oil sands have been conditioned to a desired degree. The pH of the oil sand slurry after dissolving carbon dioxide in the process water, which can be measured by a set of pH probes installed on the pipeline, is adjusted to a value below 8 and preferably

below 7 by controlling the carbon dioxide's flow rate. Since the volumetric ratio of the dissolved carbon dioxide to water is mainly decided by the water temperature and the pressure, the hydraulic pressure in the pipeline is maintained at an elevated pressure to guarantee that a desired amount of carbon dioxide is dissolved in the process water. Also, some other aspects such as the salt concentration and alkalinity of water that can affect the equilibrant carbon dioxide concentration in the aqueous phase are taken into account.

[0012] In the pipeline in which carbon dioxide is being dissolved, the hydraulic pressure is maintained between 1.1 bars to 20 bars for the purpose of dissolving more carbon dioxide and a boosting pump is installed if necessary. The pressure used in describing the invention is absolute pressure. The improvement of bitumen extraction is also facilitated by other synergetic effects due to injection of carbon dioxide, such as aeration and gas bubble floatation effect in the separation vessel and higher buoyancy of the bitumen droplets. Therefore, by maintaining an elevated hydraulic pressure in the pipeline, the volumetric flow rate ratio of carbon dioxide to the process water in the hydrotransport pipeline is controlled from 0.2:1 to 15:1. The gas volume used in this invention is its volume under standard condition. Adding carbon dioxide into the hydrotransport pipeline can be achieved by one venturi device or other gas dissolving devices such as a set of nozzles. The pressure of carbon dioxide is maintained at a pressure higher than the hydraulic pressure in the hydrotransport pipeline for the purpose of injection at a high gas flow rate, preferably between 1.5 bars to 21 bars.

[0013] To adjust the dissolved carbon dioxide concentration in the oil sands slurry, a fresh water stream can be optionally mixed with the oil sands slurry flow prior to being fed into the primary separation tank. The volumetric mixing ratio of the fresh water to the oil sands slurry is from 0:1 to 3:1. The water's temperature can be controlled from 20 °C to 120 °C. Also, the invention comprises a carbon dioxide

recycling pipeline to recover the released carbon dioxide from the oil sands slurry in the primary separation vessel, in which the operating pressure is at ambient pressure or a pressure lower than the hydraulic pressure in the pipeline. The recovered carbon dioxide can be stored in a carbon dioxide storage tank or be injected into another hydrotransport pipeline in parallel operation with or without treatment, depending on the insoluble gas concentration in it. Since a part of carbon dioxide that dissolved in the process water under ambient pressure is not recoverable, supplementary carbon dioxide is provided to maintain the carbon dioxide flow rate. To reduce corrosion of equipment caused by the dissolved carbon dioxide in water and to recycle process water for continuous conditioning of oil sands in the hydrotransport pipeline under basic conditions, the process water recovered from the separation vessel is aerated by air or other inert gases such as nitrogen, methane, carbon monoxide and argon, or is heated to an elevated temperature by injection of steam.

BRIEF DESCRIPTION OF THE DRAWINGS

[0014] The figure is a schematic process flow diagram showing injection of carbon dioxide in the hydrotransport pipeline in the oil sands hot water extraction process.

DETAILED DESCRIPTION OF THE INVENTION

[0015] As shown in the schematic process flow diagram, carbon dioxide from carbon dioxide tank A is injected into the hydrotransport pipeline 3, which transports oil sands slurry to an extraction plant, through line 2, at a position where the oil sands slurry has been conditioned to a desired degree higher than 50%, preferably higher than 80%, and more preferably higher than 90%, that the basic condition is no longer required for liberation of bitumen from sand grains. The carbon dioxide

may be supplied to the carbon dioxide tank A through line 1 from a trailer or other ready source of carbon dioxide. In order to neutralize the slurry by dissolving a desired amount of carbon dioxide in the process water, the hydrotransport pipeline 3 pressure for carbon dioxide injection is maintained at an elevated pressure from 1.2 bars to 21 bars, preferably from 3 bars to 10 bars. The pH of the oil sands slurry in the hydrotransport pipeline 3, which can be measured by a set of pH probes installed on the hydrotransport pipeline 3, is adjusted to a level below 8 and preferably below 7 by controlling the carbon dioxide flow rate.

[0016] Carbon dioxide can be directly injected in oil sand slurry through a set of nozzles or a gas disperser such as a venturi device. Although it is not necessary that all carbon dioxide be dissolved in the oil sands slurry since existence of gas bubbles in the slurry improves conditioning effect, an elevated pressure is maintained in the pipeline to keep as much as possible of carbon dioxide is dissolved in the oil sands slurry. The pressure in the hydrotransport pipeline 3 behind the carbon dioxide injection point is maintained between 1.1 bars to 20 bars, preferably between 2 bars to 10 bars. The length of the hydrotransport pipeline 3 for dissolving carbon dioxide and the residence time of oil sands slurry in the hydrotransport pipeline 3 for breaking emulsion are decided by the hydraulic pressure, the slurry's pH, amount of impurities in water such as suspended fine particles, alkalinity of the process water and the emulsification degree of bitumen in water, preferably from 1 meter to 2 kilometers, more preferably from 100 meters to 1 kilometer. The volumetric flow rate ratio of carbon dioxide to the process water in the hydrotransport pipeline 3 is controlled from 0.2:1 to 15:1, preferably from 0.5:1 to 10:1.

[0017] The oil sands slurry is fed into the hydrotransport pipeline 3 from mixer B through line 12. The oil sands slurry is fed into mixer B through line 9; hot water is also fed into the mixer B through line 8 to line 11 and additives such as sodium

hydroxide or sodium carbonate are also fed into the mixer B through line 10. The mixer B is typically a cyclofeeder. The hot water in line 8 can also be directed immediately or in addition to its transport into line 11 and mixer B, directly into the hydrotransport pipeline 3.

[0018] Before the carbon dioxide-bearing oil sands slurry is added into the primary separation vessel C or other separation vessels, the oil sands slurry flow in hydrotransport pipeline 3 is merged with a fresh water stream through line 8 to adjust the volumetric ratio of gas to water for the purpose of optimizing the gas flotation effect for bitumen in the vessel. The mixing volumetric flow rate ratio of the fresh water to oil sands slurry is controlled from 0:1 to 3:1, preferably from 0.1:1 to 1:1. And the water's temperature is controlled from 20 °C to 120 °C. After dilution, the oil sands slurry is fed into the separation vessel C through a pressure reducing device such as a nozzle or a valve.

[0019] In this embodiment, the primary separation vessel C is operated under ambient pressure or a pressure lower than the hydraulic pressure in the hydrotransport pipeline 3. Therefore, a part of carbon dioxide dissolved in water and bitumen transforms into bubbles after pressure drop to provide additional bitumen separation and flotation effects in the separation vessel. Gaseous carbon dioxide in the primary vessel's overhead space can be recycled through a carbon dioxide recovery pipeline 7 to a carbon dioxide storage tank A or be directly injected into another hydrotransport pipeline in parallel operation, not shown. The recycled carbon dioxide may contain air entrained in oil sands during conditioning, so the carbon dioxide is diluted by fresh carbon dioxide or be treated by other measures to control the insoluble gas concentration in it if it is necessary. The overall impurities concentration in carbon dioxide is controlled lower than 20%, preferably less than 10%, and more preferably less than 5% by volume. Also, the recovered carbon can be used for other purposes.

[0020] The primary separation vessel C is typically a large, conical-bottomed, cylindrical vessel. The primary separation vessel C will separate the oil sand slurry that is fed through hydrotransport pipeline 3 into three distinct components plus excess carbon dioxide that may be present in the oil sand slurry. The sand and water will exit through the bottom of the primary separation vessel C through the bottom line 6 which can be treated and returned to where the oil sand was originally derived from or transported for other disposal means. The middlings which are separated in the primary separation vessel C are removed through line 5 and froth is removed through line 4. As mentioned previously, carbon dioxide is recovered and recycled through line 7 back to the carbon dioxide storage tank A where it can be used for injection into the hydrotransport pipeline 3.

[0021] Since the process water recovered through line 6 from the separation vessel C contains dissolved carbon dioxide, which may cause corrosion of the equipments and pipelines and require additional caustic reagent to condition the oil sands when the recovered water is to be reused, the process water is aerated by air or other inert gases such as nitrogen, methane, carbon monoxide and argon, or is heated to a higher temperature by injection of steam or other heating methods before reuse.

[0022] In another embodiment, carbon dioxide is mixed with a fresh water stream before being added in the oil sands slurry. The purpose of mixing the fresh water with carbon dioxide is to make carbon dioxide partially dissolved in water at a pressure higher than the pressure in the pipeline. The fresh water's temperature can be higher or lower than the oil sands slurry's temperature transported in the pipeline. The volumetric flow rate ratio of the carbon dioxide to fresh water is controlled from 1:0 to 20:1. The water's temperature is controlled from 1°C to 100 °C.

[0023] In another further embodiment, the carbon dioxide is injected into the hydrotransport pipeline at several points and the distance between two adjacent points is from 1 meter to 500 meters, more likely from 10 meter to 200 meters. The number of injection points is from 2 to 20 and the carbon dioxide's injection rate at different injection points can be the same, close to or different at each injection point. The flow rate ratio of the overall of carbon dioxide to the process water in the oil sands slurry is from 0.2:1 to 15:1, preferably from 0.5:1 to 10:1.

[0024] While this invention has been described with respect to particular embodiments thereof, it is apparent that numerous other forms and modifications of the invention will be obvious to those skilled in the art. The appended claims in this invention generally should be construed to cover all such obvious forms and modifications which are within the true spirit and scope of the invention.

Having thus described the invention, what we claim is:

1. A method for recovering bitumen comprising adding carbon dioxide to a pipeline containing an oil-bearing formation being transported.
2. The method as claimed in claim 1 wherein said oil-bearing formation is being transported to a processing plant.
3. The method as claimed in claim 1 wherein said oil-bearing formation is selected from the group consisting of an oil sands slurry, tar sands slurry and oil-contaminated soil slurry.
4. The method as claimed in claim 1 wherein the volumetric flow rate ratio of said carbon dioxide to process water in said pipeline is controlled from 0.2:1 to 15:1.
5. The method as claimed in claim 1 wherein the volumetric flow rate ratio of said carbon dioxide to process water in said pipeline is controlled from 0.5:1 to 10:1.
6. The method as claimed in claim 1 wherein said carbon dioxide injection pressure is maintained at a pressure from 1.2 bars to 21 bars.
7. The method as claimed in claim 1 wherein said carbon dioxide injection pressure is maintained at a pressure from 3 bars to 10 bars.
8. The method as claimed in claim 1 wherein the pressure in the pipeline behind the carbon dioxide injection point is maintained between 1.1 bars to 20 bars.
9. The method as claimed in claim 1 wherein the pressure in the pipeline behind the carbon dioxide injection point is maintained between 2 bars to 10 bars.

10. The method as claimed in claim 4 wherein the pressure is maintained by a boost pump.
11. The method as claimed in claim 3 wherein the pH of the oil sands slurry in the pipeline is adjusted to a level below 8.
12. The method as claimed in claim 11 wherein the pH of the oil sands slurry is adjusted by controlling the carbon dioxide flow rate.
13. The method as claimed in claim 11 wherein the pH is measured by a set of pH probes installed on the pipeline.
14. The method as claimed in claim 1 wherein said carbon dioxide is injected in the pipeline at a point where the oil-bearing formation has been conditioned to a degree higher than 50%.
15. The method as claimed in claim 1 wherein said carbon dioxide is injected in the pipeline at a point where the oil-bearing formation has been conditioned to a degree higher than 80%.
16. The method as claimed in claim 1 wherein the length of said pipeline is from 1 meter to 2 kilometers.
17. The method as claimed in claim 16 wherein the length of said pipeline is from 100 meters to 1 kilometer.

18. The method as claimed in claim 1 wherein the oil-bearing formation flow is merged with a fresh water stream before it is fed to a separation vessel and the volumetric flow rate ratio of the fresh water to oil-bearing formation is from 0:1 to 3:1.
19. The method as claimed in claim 18 wherein the volumetric flow rate ratio of the fresh water to oil-bearing formation is from 0.1:1 to 1:1.
20. The method as claimed in claim 1 wherein said carbon dioxide is directly injected into said oil-bearing formation through a device selected from the group consisting of nozzles and a venturi device.
21. The method as claimed in claim 18 wherein the temperature of the water is from 20 °C to 120 °C.
22. The method as claimed in claim 1 wherein the carbon dioxide-bearing oil-bearing formation is fed into said separation vessel through a device selected from the group consisting of a nozzle and pressure reducing.
23. The method as claimed in claim 22 wherein said separation vessel is operated under ambient pressure.
24. The method as claimed in claim 23 wherein said separation vessel is operated at a pressure lower than the pressure in said hydrotransport pipeline.
25. The method as claimed in claim 22 wherein gaseous carbon dioxide in the separation vessel is recycled through a carbon dioxide recovery pipeline to a carbon dioxide storage tank.

26. The method as claimed in claim 22 wherein gaseous carbon dioxide in the separation vessel is recycled through a carbon dioxide recovery pipeline and directly injected in a separate pipeline in parallel operation.
27. The method as claimed in claim 26 wherein the impurity concentration in said recycled carbon dioxide is lower than 20%.
28. The method as claimed in claim 18 wherein water is recycled from the separation vessel and is aerated by a gas selected from the group consisting of air, nitrogen, methane, carbon monoxide and argon.
29. The method as claimed in claim 28 wherein the recycled water from the separation vessel is heated to a higher temperature by injection of steam or other heating methods before reuse.
30. The method as claimed in claim 1 wherein carbon dioxide is mixed with a water stream before being injected in the pipeline.
31. The method as claimed in claim 30 wherein the volumetric flow rate ratio of said carbon dioxide to said water is from 1:0 to 20:1.
32. The method as claimed in claim 31 wherein the temperature of the water is from 1 °C to 100 °C.
33. The method as claimed in claim 1 wherein carbon dioxide is injected in the pipeline at several points.
34. The method as claimed in claim 33 wherein the distance between two adjacent injection points is from 1 meter to 500 meters.

35. The method as claimed in claim 33 wherein the number of said injection points is from 2 to 20.
36. The method as claimed in claim 33 wherein the injection rates of carbon dioxide will be the same or different at said several points.
37. The method as claimed in claim 30 wherein the volumetric flow rate ratio of the carbon dioxide to the water in the oil-bearing formation is from 0.2:1 to 15:1.
38. The method as claimed in claim 37 wherein the volumetric flow rate ratio of the carbon dioxide to the water in the oil-bearing formation is from 0.5:1 to 10:1.

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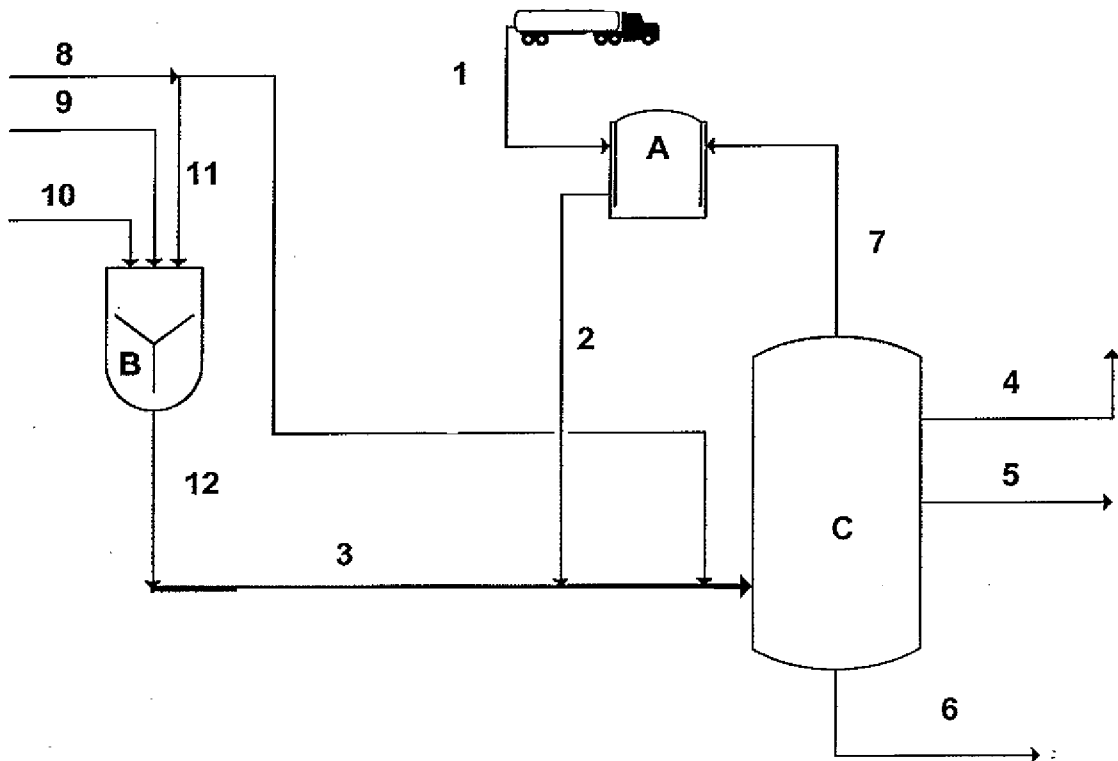


FIGURE 1

INTERNATIONAL SEARCH REPORT

International application No.

PCT/US 12/24938

A. CLASSIFICATION OF SUBJECT MATTER IPC(8) - C10G 1/04 (2012.01) USPC - 208/391; 208/390 According to International Patent Classification (IPC) or to both national classification and IPC		
B. FIELDS SEARCHED Minimum documentation searched (classification system followed by classification symbols) IPC(8)- C10G 1/04 (2012.01); USPC- 208/391; 208/390 Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched Patents and NPL (classification, keyword; search terms below) Electronic data base consulted during the international search (name of data base and, where practicable, search terms used) PubWest (US Pat, PgPub, EPO, JPO), GoogleScholar (PL, NPL), FreePatentsOnline (US Pat, PgPub, EPO, JPO, WIPO, NPL); search terms: bitumen, extract, recovery, heavy, oil, pipeline, transport, carbon, dioxide, CO2, inject, add, pressure		
C. DOCUMENTS CONSIDERED TO BE RELEVANT		
Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2010/0307959 A1 (HONG et al.) 09 December 2010 (09.12.2010), Fig. 1; para [0008]-[0013], [0029], [0039], [0044], [0045], [0050], [0055]-[0063], [0067], [0070]-[0075], [0081], [0094]	1-38
X, P ----- Y, P	US 2011/0114340 A1 (SEGERSTROM) 19 May 2011 (19.05.2011), para [0009]-[0046]	1 ----- 2-38
Y	US 2010/0155048 A1 (HACKETT et al.) 24 June 2010 (24.06.2010), para [0010]-[0076]	1-38
Y	US 2009/0250380 A1 (DANA et al.) 08 October 2009 (08.10.2009), para [0007]-[0092]	1-38
Y	US 2005/0211434 A1 (GATES et al.) 29 September 2005 (29.09.2005), para [0025]-[0072]	1-38
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Date of the actual completion of the international search 16 May 2012 (16.05.2012)		Date of mailing of the international search report 29 MAY 2012
Name and mailing address of the ISA/US Mail Stop PCT, Attn: ISA/US, Commissioner for Patents P.O. Box 1450, Alexandria, Virginia 22313-1450 Facsimile No. 571-273-3201		Authorized officer: Lee W. Young PCT Helpdesk: 571-272-4300 PCT OSP: 571-272-7774