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- (71) Applicant (for all designated States except US): **EXXON-MOBIL UPSTREAM RESEARCH COMPANY** [US/US]; P.O. Box 2189 (CORP-URC-SW359), Houston, TX 77252-2189 (US).
- (72) Inventor; and
- (71) Applicant (for US only): **CHAKRABARTY, Tapantosh** [CA/US]; 40 Edcath Road NW, Calgary, AB T2L 2K8 (CA).
- (74) Agents: **BELL, Annora, A.** et al.; Exxonmobil Upstream Research Company, P.O. Box 2189 (CORP-URC-SW359), Houston, TX 77252-2189 (US).

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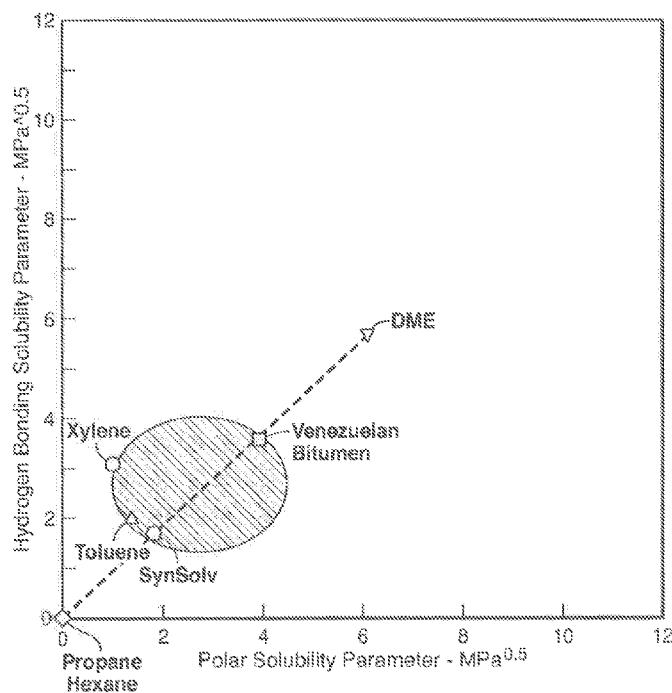
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[Continued on next page]

(54) Title: DILUTING AGENT FOR DILUTING VISCOUS OIL



(57) Abstract: Described herein is a diluting agent comprising: (a) an ether with 2 to 8 carbon atoms; and (b) a non-polar hydrocarbon with 2 to 30 carbon atoms, for diluting viscous oil, for instance bitumen. As one example, the diluting agent may be di-methyl ether and propane. The dilution may be in-situ or at surface.



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DILUTING AGENT FOR DILUTING VISCOUS OIL

CROSS REFERENCE TO RELATED APPLICATIONS

[0001] This application claims the benefit of Canadian patent application number 2,781,273 filed on June 28, 2012 entitled DILUTING AGENT FOR DILUTING VISCOUS OIL, the entirety of which is incorporated herein.

FIELD OF THE INVENTION

[0002] The present invention relates generally to diluting agents for use in diluting viscous oil, for instance bitumen.

10 BACKGROUND OF THE INVENTION

[0003] Bitumen and heavy oil (collectively referred to herein as “viscous oil” as further defined below) reserves exist at varying depths beneath the earth’s surface. More shallow reserves are often mined followed by surface extraction. Deeper reserves are often exploited by *in-situ* processes.

15 **[0004]** Diluting agents have been used for both *in-situ* and surface extraction processes
to dilute viscous oil. The term “solvent” is often used in the industry and literature in place of
“diluting agent”.

Surface Extraction

[0005] Oil sand deposits near the surface may be recovered by open-pit mining techniques, using powered shovels to remove the oil sand and load the trucks for transport to an extraction plant. Because the bitumen itself is a highly viscous material, separating it from the sands poses certain practical difficulties. The extraction of bitumen from oil sands mined in such a manner involves the liberation and separation of bitumen from the associated sands in a form that is suitable for further processing to produce a marketable product. Among several processes for bitumen extraction, the Clark Hot Water Extraction (CHWE) process represents a well-developed commercial recovery technique. In the CHWE process, mined oil sands are mixed with hot water to create slurry suitable for extraction. Caustic may be added to adjust the slurry pH to a desired level and thereby enhance the efficiency of the separation of bitumen. Recent industry developments have shown the feasibility of operating at lower temperatures and without caustic addition in the slurryfying process.

[0006] The result of most of the CHWE processes is an extract that typically comprises two parts: a hydrocarbon predominant phase (known as a bitumen froth stream), and a

tailings stream made up of coarse solids, some fine solids, and water. The specific properties of the tailings will vary depending on the extraction method used, but the tailings essentially comprise spent water, reagents (e.g. surfactants), and waste ore once the recovered bitumen has been removed. A typical composition of the bitumen froth stream is about 60 wt% bitumen, 30 wt% water and 10 wt% mineral matter (solids), with some variations to account for the extraction and processing conditions. The water and mineral matter in the froth are considered as contaminants and must be either essentially eliminated or reduced to a level suitable for pipeline transportation, feed to an oil refinery or an upgrading facility.

10 **[0007]** The processes to reject the water and mineral matter contaminants are known as froth treatment processes. Due to the high viscosity of bitumen, the first step in such processes is usually the introduction of a solvent. There are two major commercial approaches to reject the froth contaminants, namely naphtha solvent-based froth treatment and paraffinic solvent-based froth treatment. Solvent addition increases the density differential between bitumen and water and mineral matter and enables contaminants rejection, which can be carried out by any number of methods, such as centrifugation or gravity separation using multi-stage gravity settling units. The separation schemes generally result in a product effluent stream of diluted bitumen ("dilbit") and a reject or tailings stream, commonly referred to as the froth treatment tailings, comprising mineral matter, water, residual solvent, and some residual bitumen. More specifically, in a paraffinic froth treatment process the solvent dilution induces the precipitation of asphaltenes from the bitumen as an additional contaminant that results in an improvement in the efficiency of the contaminant rejection process.

25 **[0008]** An example of naphtha froth treatment (NFT) is described in U.S. Patent No. 5,236,577. Addition of naphtha and separation may yield a bitumen product containing 1 to 3 wt% water and < 1.0 wt% solids. Such product composition does not meet pipeline specifications and renders the NFT product stream unsuitable for transportation through a common pipeline carrier.

30 **[0009]** Examples of paraffinic froth treatment (PFT) are described in Canadian Patents Nos. 2,149,737 and 2,217,300. The addition of sufficient amounts of paraffinic solvent results in asphaltene precipitation, formation of aggregates with the contaminants (entrained water and carryover solids in the froth), and settling. Conventional treaters which separate water and mineral matter will not remove very fine particulate ("fines") from the froth. Therefore, PFT settling vessels are sized to allow gravity settling of fines and other contaminants to provide a solids-free dry bitumen product (< 300 wppm solids, < 0.5%

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BS&W) suitable for transportation in a common carrier to refineries. Bitumen of such quality is termed "fungible" because it can be processed in conventional refinery processes, such as hydroprocessing, without dramatically fouling the refinery equipment.

5 **[0010]** The CHWE process, described above, is the most commonly employed water-based extraction process. In the case of water-based extraction, water is the dominant liquid in the process and the extraction occurs by having water displace the bitumen on the surface of the solids.

10 **[0011]** Solvent-based extraction processes for the recovery of the hydrocarbons have been proposed as an alternative to water-based extraction of mined oil sands. In the case of solvent-based extraction, the solvent is the dominant liquid and the extraction of the bitumen occurs by dissolving bitumen into the solvent. A challenge of certain solvent-based extraction of oil sands can be the tendency of fine particles within the oil sands to hamper the separation of solids from the hydrocarbon extract. Solvent extraction with solids agglomeration is a technique that has been proposed to deal with this challenge. The
15 original application of this technology was coined Solvent Extraction Spherical Agglomeration (SESA). A more recent description of the SESA process can be found in Sparks et al., Fuel 1992(71); pp 1349-1353.

20 **[0012]** Previously described methodologies for SESA have not been commercially adopted. In general, the SESA process involves mixing oil sands with a hydrocarbon solvent, adding a bridging liquid to the oil sands slurry, agitating the mixture in a slow and controlled manner to nucleate particles, and continuing such agitation to permit these nucleated particles to form larger multi-particle spherical agglomerates for removal. The bridging liquid is preferably water or an aqueous solution since the solids of oil sands are mostly hydrophilic and water is immiscible with hydrocarbon solvents.

25 **[0013]** The SESA process described by Meadus et al. in U.S. Patent No. 4,057,486, involves combining solvent extraction with solids agglomeration to achieve dry tailings suitable for direct mine refill. In the process, organic material is separated from oil sands by mixing the oil sands material with an organic solvent to form a slurry, after which an aqueous bridging liquid is added in the amount of 8 to 50 wt% of the feed mixture. By using controlled
30 agitation, solid particles from oil sands come into contact with the aqueous bridging liquid and adhere to each other to form macro-agglomerates of a mean diameter of 2 mm or greater. The formed agglomerates are more easily separated from the organic extract compared to un-agglomerated solids. This process permitted a significant decrease in water use, as compared with conventional water-based extraction processes. Furthermore, the
35 organic extract produced has significantly lower amounts of solids entrained within

compared to previously described solvent-based extraction methods.

[0014] Solvent extracted bitumen has a much lower solids and water content than that of bitumen froth produced in the water-based extraction process. However, the residual amounts of water and solids contained in solvent extracted bitumen may nevertheless render
5 the bitumen unsuitable for marketing. Removing contaminants from solvent extracted bitumen is difficult using conventional separation methods such as gravity settling, centrifugation or filtering.

[0015] Another example of a solvent-based extraction process is described in Canadian Patent Application Serial No. 2,724,806 ("Adeyinka et al."), published June 30, 2011 and
10 entitled "Processes and Systems for Solvent Extraction of Bitumen from Oil Sands".

In-Situ Processes

[0016] Where deposits lie well below the surface, viscous oil may be extracted using *in-situ* ("in place") techniques. For *in-situ* recovery processes, diluting agents have been injected alone and in combination with steam. Diluting agents reduce the viscosity of
15 viscous oil by dilution, while steam reduces the viscosity of viscous oil by raising the viscous oil temperature. Reducing the viscosity of *in-situ* viscous oil is done to permit or facilitate its production.

[0017] One example of an *in-situ* technique is the steam-assisted gravity drainage method (SAGD). In SAGD, directional drilling is employed to place two horizontal wells in
20 the oil sands – a lower well and an upper well positioned above it. Steam is injected into the upper well to heat the bitumen and lower its viscosity. The bitumen and condensed steam will then drain downward through the reservoir under the action of gravity and flow into the lower production well, whereby these liquids can be pumped to the surface. At the surface of the well, the condensed steam and bitumen are separated, and the bitumen is diluted with
25 appropriate light hydrocarbons for transport to a refinery or an upgrader. An example of SAGD is described in U.S. Patent No. 4,344,485 (Butler).

[0018] In other processes, such as in Cyclic Steam Stimulation (CSS), the same well is used both for injecting a fluid and for producing oil. In CSS, cycles of steam injection, soak, and oil production are employed. Once the production rate falls to a given level, the well is
30 put through another cycle of injection, soak, and production. An example of CSS is described in U.S. Patent No. 4,280,559 (Best).

[0019] Steam Flooding (SF) involves injecting steam into the formation through an injection well. Steam moves through the formation, mobilizing oil as it flows toward the production well. Mobilized oil is swept to the production well by the steam drive. An

example of steam flooding is described in U.S. Patent No. 3,705,625 (Whitten).

[0020] Other thermal processes include Solvent-Assisted Steam Assisted Gravity Drainage (SA-SAGD), an example of which is described in Canadian Patent No. 1,246,993 (Vogel); Vapour Extraction (VAPEX), an example of which is described in U.S. Patent No. 5,899,274 (Frauenfeld); Liquid Addition to Steam for Enhanced Recovery (LASER), an example of which is described in U.S. Patent No. 6,708,759 (Leaute et al.); and Combined Steam and Vapour Extraction Process (SAVEX), an example of which is described in U.S. Patent No. 6,662,872 (Gutek), and derivatives thereof. These processes employ a “diluting agent”.

10 **[0021]** Solvent-dominated recovery processes (SDRPs) are another category of *in-situ* processes where solvent is used to reduce the viscosity of the viscous oil. At the present time, solvent-dominated recovery processes (SDRPs) are rarely used to produce highly viscous oil. In certain described SDRPs, the solvent is heated.

[0022] Cyclic solvent-dominated recovery processes (CSDRPs) have also been proposed. CSDRPs are a subset of SDRPs. A CSDRP may be, but is not necessarily, a generally non-thermal recovery method that uses a solvent (or “diluting agent”) to mobilize viscous oil by cycles of injection and production. In a CSDRP, a viscosity-reducing solvent is injected through a well into a subterranean viscous-oil reservoir, causing the pressure to increase. Next, the pressure is lowered and reduced-viscosity oil is produced to the surface through the same well through which the solvent was injected. Multiple cycles of injection and production are used. In some instances, a well may not undergo cycles of injection and production, but only cycles of injection or only cycles of production. CSDRPs may be particularly attractive for thinner or lower-oil-saturation reservoirs. In such reservoirs, thermal methods utilizing heat to reduce viscous oil viscosity may be inefficient due to excessive heat loss to the overburden and/or underburden and/or reservoir with low oil content. References describing specific CSDRPs include: Canadian Patent No. 2,349,234 (Lim et al.); G. B. Lim et al., “Three-dimensional Scaled Physical Modeling of Solvent Vapour Extraction of Cold Lake Bitumen”, The Journal of Canadian Petroleum Technology, 35(4), pp. 32-40, April 1996; G. B. Lim et al., “Cyclic Stimulation of Cold Lake Oil Sand with Supercritical Ethane”, SPE Paper 30298, 1995; US Patent No. 3,954,141 (Allen et al.); and M. Feali et al., “Feasibility Study of the Cyclic VAPEX Process for Low Permeable Carbonate Systems”, International Petroleum Technology Conference Paper 12833, 2008. The family of processes within the Lim et al. references describe embodiments of a particular SDRP that is also a cyclic solvent-dominated recovery process (CSDRP). These processes relate to the recovery of heavy oil and bitumen from subterranean reservoirs using cyclic injection

of a solvent in the liquid state which vaporizes upon production. The family of processes within the Lim et al. references may be referred to as CSPTM processes. Another example of a CSDRP is described in Canadian Patent Document No. 2,688,392 (Lebel et al., published June 9, 2011). In certain CSDRPs, there may be the formation of a second liquid phase
5 whose high viscosity may affect the mobility of heavy oil and bitumen, and may thereby impact their recovery.

[0023] In certain predominantly non-thermal CSDRPs, while heat is not used to reduce the viscosity of the viscous oil, the use of heat is not excluded. Heating may be beneficial to improve performance or start-up. For start-up, low-level heating (for example, less than
10 100 °C) may be appropriate. Low-level heating of the solvent prior to injection may also be performed to prevent hydrate formation in tubulars and in the reservoir. Heating to higher temperatures may also benefit recovery.

[0024] Canadian Patent No. 2,652,930 (Ignasiak et al., published July 20, 2010) describes, according to the Abstract, a method “for energy efficient, environmentally friendly,
15 *in-situ* recovery of viscous oil or heavy oil by injecting di-methyl ether (DME) into the reservoir. The method includes the steps of heating the reservoir utilizing the condensation and latent heats of injected DME liquids and/or vapours, mobilizing the viscous oil/heavy oil by lowering its viscosity, dissolving the water and some of the components of the viscous oil/heavy oil in the DME, recovering from the reservoir the mixture of viscous oil and DME
20 containing the dissolved components of the viscous oil, separating the DME from the mixture by depressurization followed by pressurizing, heating and re-injecting the recovered DME, into the reservoir.” Potential disadvantages of DME alone may include DME loss in water in the reservoir, and compatibility issues with seal materials in process equipment, pump and vessels.

25 **[0025]** It is desirable to provide an improved or alternative diluting agent for diluting viscous oil for use in surface extraction or *in-situ* processes.

SUMMARY OF THE INVENTION

[0026] Generally, described herein is a diluting agent comprising: (a) an ether with 2 to 8 carbon atoms; and (b) a non-polar hydrocarbon with 2 to 30 carbon atoms, for diluting
30 viscous oil. The dilution may be *in-situ* or at surface.

[0027] Other aspects and features of the present invention will become apparent to those ordinarily skilled in the art upon review of the following description of specific embodiments of the invention in conjunction with the accompanying figures.

BRIEF DESCRIPTION OF THE DRAWINGS

[0028] Embodiments of the present invention will now be described, by way of example only, with reference to the attached Figures, wherein:

[0029] Fig. 1 is a graph illustrating hydrogen bonding solubility parameter versus polar
5 solubility parameter of various diluting agents.

[0030] Fig. 2 is a graph illustrating bitumen recovery using various diluting agents.

[0031] Fig. 3 is a graph illustrating the percentage improvement in bitumen recovery by various blends of di-methyl ether and propane over propane alone.

DETAILED DESCRIPTION

10 **[0032]** The term "viscous oil" as used herein means a hydrocarbon, or mixture of hydrocarbons, that occurs naturally and that has a viscosity of at least 10 cP (centipoise) at initial reservoir conditions. Viscous oil includes oils generally defined as "heavy oil" or "bitumen". Bitumen oil is classified as an extra heavy oil, with an API gravity of about 10° or less, referring to its gravity as measured in degrees on the American Petroleum Institute
15 (API) Scale. Heavy oil has an API gravity in the range of about 22.3° to about 10°. The terms viscous oil, heavy oil, and viscous oil are used interchangeably herein since they may be extracted using similar processes. Viscous oil also includes hydrocarbon refinery intermediates and residual hydrocarbon waste streams resulting from both surface extraction, for instance solvent based extraction and water-based extraction, as well as from
20 *in-situ* recovery processes, for instance SAGD, SA-SAGD, CSS, SDRP, CSDRP, and other processes described herein.

[0033] *In-situ* is a Latin phrase for "in the place" and, in the context of hydrocarbon recovery, refers generally to a subsurface hydrocarbon-bearing reservoir. For example, an *in-situ* oil recovery technique is one that recovers oil from a reservoir within the earth.

25 **[0034]** The term "formation" as used herein refers to a subterranean body of rock that is distinct and continuous. The terms "reservoir" and "formation" may be used herein interchangeably.

[0035] "Diluting Agent" means a fluid of a lower viscosity and lower density than those of a viscous oil with which it is mixed or blended. Its viscosity may, for example, be 0.2 to 5 cp
30 at room temperature and at a pressure high enough to make it liquid. Its density may be, for example, 450 to 750 kg/m³ at 15 °C and at a pressure high enough to make it liquid. The mixture or the blend of diluting agent and viscous oil has a viscosity and a density that is in between those of the diluting agent and the viscous oil. The diluting agent may or may not

precipitate asphaltenes if its concentration exceeds a critical concentration. In addition to reducing viscosity for the purpose of extracting bitumen at surface or *in-situ*, the diluting agent can also be used to reduce viscosity and density for the purpose of separating emulsified water droplets from viscous oil.

5 **[0036]** Diluting agents that have previously been suggested for viscous oil recovery include, but are not limited to, n-alkanes, such as ethane, propane, butane, normal- and iso-pentane, cycloalkanes like cyclopentane and cyclohexane, and gas plant condensates (a mixture of n-alkanes, naphthenes and aromatics). These diluting agents can cause asphaltenes precipitation when their concentrations exceed certain limits. The precipitated
10 asphaltenes may adversely affect the permeability of the reservoir. Avoiding asphaltenes precipitation is not necessarily a requirement of embodiments described herein. Aromatic diluting agents, such as toluene and xylene, are excellent diluting agents for viscous oil by being miscible with viscous oil in all proportions and dissolving all four components of viscous oil: saturates, aromatics, resins and asphaltenes (SARA). The aromatic diluting
15 agents, however, are not generally considered for viscous oil recovery because of their cost, material safety, and relatively higher boiling points (for example 110 to 144 °C), the latter leading to poor diluting agent recovery from the reservoir. Ideally, a diluting agent would possess good solvency power (as do aromatic diluting agents) but have a lower boiling point than do aromatics.

20 **[0037]** As described above in the Summary section, described herein is a diluting agent comprising: (a) an ether with 2 to 8 carbon atoms; and (b) a non-polar hydrocarbon with 2 to 30 carbon atoms, for diluting viscous oil. The dilution may be *in-situ* or at surface.

25 **[0038]** The ether may have 2 to 4 carbon atoms. The ether may be di-methyl ether, methyl ethyl ether, di-ethyl ether, methyl iso-propyl ether, methyl propyl ether, di-isopropyl ether, di-propyl ether, methyl iso-butyl ether, methyl butyl ether, ethyl iso-butyl ether, ethyl butyl ether, iso-propyl butyl ether, propyl butyl ether, di-isobutyl ether, or di-butyl ether. The ether may be di-methyl ether. The ether may be di-ethyl ether.

30 **[0039]** The non-polar hydrocarbon may be a C2-C30 alkane, a C2-C30 n-alkane, C2-C20 alkane, a C2-C20 n-alkane, a C2-C5 alkane, propane, a C5-C7 cycloalkane, or cyclohexane.

35 **[0040]** The non-polar hydrocarbon may be a mixture of non-polar hydrocarbons, the non-polar hydrocarbons being C2-C30 alkanes, the mixture being substantially aliphatic and substantially non-halogenated. "Substantially aliphatic and substantially non-halogenated" means less than 10% by weight of aromaticity and with no more than 1 mole percent halogen atoms. In other embodiments, the level of aromaticity is less than 5, less than 3,

less than 1, or 0 % by weight.

[0041] The non-polar hydrocarbon may be a mixture of non-polar hydrocarbons and may be a gas plant condensate comprising at least one C3-C17 n-alkane, at least one C5-C7 cycloalkane, and at least one C6-C8 aromatic hydrocarbon.

- 5 **[0042]** The non-polar hydrocarbon may be an alkane, for example ethane, propane, butane, normal- and iso-pentane, hexane, heptane, or other higher molecular weight alkanes. In one embodiment, the alkane has up to 10 carbon atoms per molecule. In one embodiment, the alkane has up to 20 carbon atoms per molecule. In one embodiment, the alkane has up to 30 carbon atoms per molecule. In one embodiment, the non-polar component of the blend has a low-boiling point of less than 125 °C that can be easily separated from *in-situ* or surface-extracted solvent-diluted bitumen. Alkanes have been previously suggested as bitumen solvents. Compared to toluene and xylene, which dissolve all the four components of bitumen, namely saturates, aromatics, resins and asphaltenes (SARA), and are miscible with bitumen in all proportions, alkanes do not dissolve
- 10 asphaltene and are not miscible with bitumen at high solvent concentrations. Alkanes can be quite slow acting in that they penetrate an oil sands matrix at a slow pace, which can affect economic recovery.

[0043] The non-polar component may alternatively be another known diluting agent, such as one used in processes described in the above background section.

- 20 **[0044]** The diluting agent may be di-methyl ether and propane.

[0045] The hydrogen bonding parameter and the polarity parameter of the non-polar component may be each less than 1 MPa^{0.5}.

[0046] The diluting agent may have a volume ratio of (a):(b) of 10:90 to 90:10; or 20:80 to 70:30; or 22.5:77.5 to 50:50.

- 25 **[0047]** The diluting agent may have a viscosity of 0.2 to 5 cp at room temperature.

[0048] The diluting agent may have a density of 450 to 750 kg/m³ at 15 °C.

[0049] The diluting agent may be in liquid form.

[0050] The diluting agent may have a Hansen hydrogen bonding solubility parameter of 0.7 to 6.2.

- 30 **[0051]** The diluting agent may have a Hansen polar solubility parameter of 0.5 to 6.5.

[0052] As described in the Background section, Canadian Patent No. 2,652,930 (Ignasiak et al., published July 20, 2010) describes the use of heated di-methyl ether (DME) for *in-situ* extraction. Potential disadvantages of DME alone may include DME loss in the

reservoir water, and compatibility issues with seal materials.

[0053] As described below in the Examples section, combining DME with propane may improve oil recovery over the use of propane alone and over what would be expected based on a linear blending relationship. A blend of DME and propane may also mitigate diluting agent loss and/or be more compatible with seal materials than DME alone. A blend of DME and propane may also reduce the formation of the viscous second liquid phase that may form when propane is used alone.

Surface Extraction

[0054] The present diluting agent may be used for surface extraction of viscous oil. After extraction, the diluting agent may be recovered from the extracted sands and recycled. Diluting agent may also be recovered from the diluting agent-diluted extracted viscous oil for recycling.

[0055] The present diluting agent may provide a non-aqueous route to dilute viscous oil to eliminate, or reduce, the need for the tailings ponds. "Non-aqueous" is used herein to refer to extraction that is effected by diluting viscous oil using a diluting agent other than water; however the use of water is not necessarily excluded from the entire process as detailed in other solvent-based extraction processes described above in the Background section.

[0056] The use of the present diluting agent may extract more viscous oil in less time than at least certain conventional diluting agents.

[0057] Various solvent-based extraction methods are discussed above in the background section. The instant diluting agent may be used in such processes. For instance, the instant diluting agent may be used in a Solvent Extraction Spherical Agglomeration (SESA), descriptions of which are provided in Sparks et al., Fuel 1992(71); pp 1349-1353; and U.S. Patent No. 4,057,486 (Meadus et al.), as well as a solvent-based extraction process as described in Canadian Patent Application Serial No. 2,724,806 ("Adeyinka et al."), published June 30, 2011 and entitled "Processes and Systems for Solvent Extraction of Bitumen from Oil Sands". Examples of solvents used in Adeyinka are heptane, iso-heptane, hexane, iso-hexane, pentane, iso-pentane, a cycloalkane of 4 to 9 carbon atoms, cyclohexane, cyclopentane, and mixtures thereof.

[0058] In order to make DME a liquid, the system can be under pressure since DME boils at -24 °C at atmospheric pressure. DME should be easier to recover than cyclohexane or heptane which boil at 81 °C and 97 °C, respectively. The recovery of the diluting agent may be accomplished by reduction of pressure at or above room temperature.

In-Situ

[0059] The present diluting agent may be used for *in-situ* dilution to reduce the viscosity of viscous oil in an underground reservoir. The particular process of injection and production (including well configuration) may be a known process (with the new diluting agent), for instance one described above in the background section which uses a diluting agent (often referred to in the literature as a solvent), optionally with other fluids.

[0060] The process may be, for instance, solvent-assisted steam-assisted gravity drainage (SA-SAGD), a cyclic solvent dominated recovery process (CSDRP), a liquid addition to steam for enhanced recovery process (LASER), a vapour extraction process (VAPEX), Cyclic Steam Stimulation (CSS), or a heated solvent process.

[0061] The injection well may be horizontal, vertical, or otherwise.

[0062] The diluting agent may be injected as a liquid, as a heated liquid, as a vapor, or as a supercritical fluid.

[0063] The process may be thermal or non-thermal. "Non-thermal" means that heat is not generally used to reduce the viscosity of the viscous oil, while the use of heat is not excluded. For instance in certain non-thermal CSDRPs, heating may be beneficial to improve performance or start-up. For start-up, low-level heating (for example, less than 100 °C) may be appropriate. Low-level heating of the solvent prior to injection may also be performed to prevent hydrate formation in tubulars and in the reservoir. Heating to higher temperatures may also benefit recovery.

[0064] The diluting agent may be injected with other fluids, for instance in certain CSDRPs, co-injectants may include: diesel, viscous oil, bitumen, or diluent, to provide flow assurance, or CO₂, natural gas, C₃+ hydrocarbons, ketones, or alcohols.

[0065] The diluting may be injected with a gas plant condensate to potentially improve the effectiveness of the latter in recovering viscous oil. A gas plant condensate comprises alkanes, naphthenes, and aromatics, and is commonly used in viscous oil extraction partially because of its availability.

[0066] In one embodiment, the diluting agent may be used to dilute viscous oil between a horizontal injector well and a horizontal producer well to establish fluid communication between the two wells, prior to steam injection to start a SAGD process.

[0067] In another embodiment, the production is continuous from a neighboring horizontal or vertical well which is at some distance from the injection well.

[0068] In another embodiment, the diluting agent is injected from a horizontal well and

the diluted viscous oil is produced from a horizontal well spaced at a certain depth below the injector. Injection and production from this well pair is either continuous or cyclical.

[0069] A combination of known *in-situ* processes may also be used.

5 **[0070]** In another embodiment, the diluting agent may be used to reduce the formation of the viscous second liquid phase. In yet another embodiment, the proportion of ether and nonpolar component in the diluting agent injected can be varied over time to optimize diluent finger growth and/or minimize the viscous second liquid phase formation.

[0071] The diluent storing system can be pressurized to liquefy a lower boiling ether like DME. The separation of DME from produced fluids is simpler than that with prior solvents.
10 The present diluting agent may be particularly suitable for cyclic processes and lower pressure SA-SAGD. It may also be particularly suitable for processes where the viscous second liquid phase formation occurs and hinders mobility of bitumen and/or causes plugging in tubular, pump or process equipment. While C3 has been exemplified below as being the non-polar component in the diluting agent, other non-polar C2-C20 hydrocarbons
15 are also expected to function as they are non-polar molecules with Hansen solubility parameters similar to that of C3. While DME has been exemplified below as being the polar component in the diluting agent, other C2-C8 ethers are also expected to function as these are polar molecules with Hansen solubility parameters similar to that of DME.

Additional Embodiments and Potential Advantages

20 **[0072]** Fig. 1 is a graph of hydrogen bonding solubility parameter versus polar solubility parameter of various diluting agents (e.g. propane and hexane) and bitumen solvents (e.g., toluene and xylene). Ideally, the solubility parameters of a solvent and those of the viscous oil should be similar. The oval region in Fig.1 is a non-limiting preferred solvent region for bitumen based on experimental data. While DME and propane do not individually fall within
25 this region, their blend (shown as SynSolv in Fig. 1) does.

[0073] The diluting agent may have a Hansen hydrogen bonding parameter of 0.7 to 6.2 and a Hansen polar solubility parameter of 0.5 to 6.5.

[0074] Potential advantages of embodiments described herein may include fewer tailings than aqueous based extraction and/or a lower energy requirement to separate the
30 diluting agent from the viscous oil as compared to certain solvent-based extraction processes.

[0075] Potential advantages of embodiments described herein over certain conventional diluting agents in diluting viscous oil may include faster dilution, more efficient diluting agent separation from diluting agent-diluted viscous oil, improved environmental conditions,

improved safety conditions, and/or reduced diluting agent cost.

[0076] The diluting agent may also be used to clean viscous oil-coated equipment or vessels used in extraction processes. This may be environmentally advantageous over aromatic diluting agents, for instance toluene or xylene.

5 *Example*

[0077] Tests were conducted in a sand pack saturated with live Cold Lake bitumen at room temperature using various fluids using the following test conditions:

- Sand Pack Permeability: 5.4 D,
- Live Cold Lake Bitumen (10 CH₄ GOR),
- 10 - Confining Pressure: 7.5 MPaa; T: 21°C,
- Diluting Agents: C3, diesel, acetone, DME,
- Test protocol:

injecting a diluting agent at a constant rate of 2.7 mL/min until the pressure increases to 9.5 MPaa.

- 15 **[0078]** Injecting at a constant pressure of 9.5 MPaa and at an outlet pressure of 5 MPaa, and collecting produced bitumen in a sample cylinder until the solvent breakthrough at the end of the pack occurs.

[0079] Stopping injection at solvent breakthrough and closing outlet valve and allowing sand pack pressure to equilibrate.

- 20 **[0080]** Switching sample cylinder and injecting diluting agent at a constant rate of 2.73 ml/min for a predetermined pore volume (PV) of injection and collecting produced diluted bitumen in another sample cylinder. One PV is the total volume of the pores in the porous sand pack.

- 25 **[0081]** Monitoring pressure differential across the sand pack during diluting agent injection and recording the density of the diluted produced bitumen.

[0082] Switching sample cylinder again after the predetermined PV of diluting agent injection and continuing injection and production after several samples of produced diluted bitumen have been collected in different sample cylinders.

- 30 **[0083]** Determining the bitumen produced in different sample bottle and cylinders after removing the diluting agent from the diluted bitumen.

[0084] Cleaning the sand pack with a series of solvent injection and reusing it for the

next test.

[0085] As illustrated in Figure 2, the tests showed higher recovery using 85:15, 77.5:22.5, 70:30 and 50:50 (all v/v) blends of C3 (propane) and DME (di-methyl ether) than by C3 alone. The Hansen hydrogen bonding parameters for the blends ranged from 0.70 to 5.7 and the Hansen polar solubility parameter ranged from 0.5 to 6.10. The blends were even more effective at a higher PV. For instance, at 2.3 PV, the recovery by the 50:50 (v/v) DME:C3 blend was 65% of original bitumen in place (OBIP) as compared to a recovery of 41%. This level of recovery uplift over C3 alone seems to persist at as low as 22.5 vol% DME. At 15 vol% DME, the recovery uplift falls off but is significant (recovery of 51% OBIP for the blend vs. 42% OBIP for C3 alone).

[0086] Figure 3 compares the percentage improvement in bitumen recovery by blends of DME and C3 over C3 alone. The improvement varies from 25% (for 15 vol% DME) to 65% (at 30 vol% DME). Shown in Fig. 3 is also the expected improvement in recovery over C3 based on a linear mixing rule using the measured recovery at 100% DME. For each of the four DME-C3 blends, the measured recovery is significantly higher than that calculated from the linear rule. This indicates some unexpected synergy takes place when C3 is blended with DME. Having a wide effective or acceptable blending ratio (for instance, 22.5 to 100 vol% DME) may be useful for mitigating the effects of a variable supply and price of diluent agent(s).

[0087] The water production was also significantly lower (in the ppm range) when the DME is blended with C3, in the few hundred ppm at lower PV and increasing to a few thousand ppm at higher PV. The seal compatibility should also improve by blending DME with C3. DME alone is not compatible with seal materials but its 30:70 (V/V) blend is compatible with seal materials. The viscous second liquid phase formation observed with C3 injection was also suppressed significantly by blending DME with C3.

Numbered Embodiments

[0088] Paragraph 1. A diluting agent for diluting viscous oil, the diluting agent comprising:

- (a) an ether with 2 to 8 carbon atoms; and
- (b) a non-polar hydrocarbon with 2 to 30 carbon atoms.

[0089] Paragraph 2. The diluting agent according to Paragraph 1, wherein (a) has 2 to 4 carbon atoms.

[0090] Paragraph 3. The diluting agent according to Paragraph 1, wherein (a) is di-methyl ether, methyl ethyl ether, di-ethyl ether, methyl iso-propyl ether, methyl propyl ether,

di-isopropyl ether, di-propyl ether, methyl iso-butyl ether, methyl butyl ether, ethyl iso-butyl ether, ethyl butyl ether, iso-propyl butyl ether, propyl butyl ether, di-isobutyl ether, or di-butyl ether.

5 **[0091]** Paragraph 4. The diluting agent according to Paragraph 1, wherein (a) is di-methyl ether.

[0092] Paragraph 5. The diluting agent according to Paragraph 1, wherein (a) is di-ethyl ether.

[0093] Paragraph 6. The diluting agent according to any one of Paragraphs 1 to 5, wherein (b) is a C2-C30 alkane.

10 **[0094]** Paragraph 7. The diluting agent according to any one of Paragraphs 1 to 5, wherein (b) is a C2-C30 n-alkane.

[0095] Paragraph 8. The diluting agent according to any one of Paragraphs 1 to 5, wherein (b) is a C2-C20 alkane.

15 **[0096]** Paragraph 9. The diluting agent according to any one of Paragraphs 1 to 5, wherein (b) is a C2-C20 n-alkane.

[0097] Paragraph 10. The diluting agent according to any one of Paragraphs 1 to 5, wherein (b) is a C2-C5 alkane.

[0098] Paragraph 11. The diluting agent according to any one of Paragraphs 1 to 5, wherein (b) is propane.

20 **[0099]** Paragraph 12. The diluting agent according to any one of Paragraphs 1 to 5, wherein (b) is a C5-C7 cycloalkane.

[0100] Paragraph 13. The diluting agent according to any one of Paragraphs 1 to 5, wherein (b) is cyclohexane.

25 **[0101]** Paragraph 14. The diluting agent according to any one of Paragraphs 1 to 5, wherein (b) is a mixture of non-polar hydrocarbons, the non-polar hydrocarbons being C2-C30 alkanes, the mixture being substantially aliphatic and substantially non-halogenated.

[0102] Paragraph 15. The diluting agent according to any one of Paragraphs 1 to 5, wherein (b) is a mixture of non-polar hydrocarbons and is a gas plant condensate comprising at least one C3-C17 n-alkane, at least one C5-C7 cycloalkane, and at least one C6-C8 aromatic hydrocarbon.

30 **[0103]** Paragraph 16. The diluting agent according to Paragraph 1, wherein (a) is di-methyl ether and (b) is propane.

- [0104] Paragraph 17. The diluting agent according to any one of Paragraphs 1 to 16, wherein (b) has a hydrogen bonding parameter of less than 1 MPa^{0.5} and a polarity parameter of less than 1 MPa^{0.5}.
- [0105] Paragraph 18. The diluting agent according to any one of Paragraphs 1 to 17,
5 wherein the diluting agent has a volume ratio (a):(b) of 10:90 to 90:10.
- [0106] Paragraph 19. The diluting agent according to Paragraph 18, wherein the volume ratio is 20:80 to 70:30.
- [0107] Paragraph 20. The diluting agent according to Paragraph 18 or 19, wherein the volume ratio is 22.5:77.5 to 50:50.
- 10 [0108] Paragraph 21. The diluting agent according to any one of Paragraphs 1 to 20, wherein the diluting agent has a viscosity of 0.2 to 5 cp at room temperature.
- [0109] Paragraph 22. The diluting agent according to any one of Paragraphs 1 to 21, wherein the diluting agent has a density of 450 to 750 kg/m³ at 15°C.
- [0110] Paragraph 23. The diluting agent according to any one of Paragraphs 1 to 22,
15 wherein the diluting agent is in liquid form.
- [0111] Paragraph 24. The diluting agent according to any one of Paragraphs 1 to 23, wherein the diluting agent has a Hansen hydrogen bonding solubility parameter of 0.7 to 6.2.
- [0112] Paragraph 25. The diluting agent according to any one of Paragraphs 1 to 24, wherein the diluting agent has a Hansen polar solubility parameter of 0.5 to 6.5.
- 20 [0113] Paragraph 26. A use of the diluting agent according to any one of Paragraphs 1 to 25, for diluting viscous oil.
- [0114] Paragraph 27. The use according to Paragraph 26, wherein the diluting viscous oil is *in-situ* dilution of the viscous oil within an underground viscous oil reservoir.
- [0115] Paragraph 28. The use according to Paragraph 26 or 27, wherein the use is
25 for injecting the diluting agent into a well completed in the underground viscous oil reservoir to reduce a viscosity of the *in-situ* viscous oil.
- [0116] Paragraph 29. The use according to any one of Paragraphs 26 to 28, wherein the use is for *in-situ* viscous oil dilution by a solvent-assisted steam-assisted gravity drainage process, a cyclic solvent dominated recovery process, a liquid addition to steam for
30 enhanced recovery process, a vapour extraction process, or a heated solvent process.
- [0117] Paragraph 30. The use according to any one of Paragraphs 26 to 29, wherein the use is for *in-situ* viscous oil dilution by a cyclic solvent dominated recovery process.

[0118] Paragraph 31. The use according to Paragraph 26, for establishing fluid communication in an underground viscous oil reservoir between injector and producer wells in a solvent assisted gravity drainage process prior to steam injection.

5 **[0119]** Paragraph 32. The use according to any one of Paragraphs 26 to 28, wherein the use of the diluting agent is together with steam.

[0120] Paragraph 33. The use according to Paragraph 26, wherein the diluting viscous oil is surface dilution.

[0121] Paragraph 34. The use according to Paragraph 33, wherein the diluting viscous oil is a solvent-based extraction process.

10 **[0122]** Paragraph 35. The use according to Paragraph 26, for cleaning a viscous oil-coated surface.

[0123] Paragraph 36. A process for recovering viscous oil from an underground reservoir, the process comprising:

15 (i) injecting the diluting agent according to any one of Paragraphs 1 to 25 into the reservoir to reduce the viscosity of the viscous oil; and

(ii) producing at least a fraction of the diluting agent and the viscous oil.

20 **[0124]** Paragraph 37. The process of Paragraph 36, wherein the process is a solvent-assisted steam-assisted gravity drainage, a cyclic solvent dominated recovery process, a liquid addition to steam for enhanced recovery process, a vapour extraction process, or a heated solvent process.

[0125] Paragraph 38. The process according to Paragraph 36 or 37, wherein the process is a cyclic solvent dominated recovery process.

25 **[0126]** Paragraph 39. A process for establishing fluid communication in an underground viscous oil reservoir between injector and producer wells in a solvent assisted gravity drainage process prior to steam injection, the process comprising:

(i) providing the diluting agent according to any one of Paragraphs 1 to 25; and

(ii) injecting the diluting agent into the reservoir to establish the fluid communication.

30 **[0127]** Paragraph 40. A process for diluting viscous oil at surface, the process comprising:

(i) providing viscous oil; and

(ii) combining the diluting agent according to any one of Paragraphs 1 to 25 with

the viscous oil to dilute the viscous oil.

[0128] Paragraph 41. A process for cleaning a viscous oil-coated surface, the process comprising:

- (i) providing the diluting agent according to any one of Paragraphs 1 to 25; and
- 5 (ii) applying the diluting agent to the viscous oil-coated surface to clean the viscous oil-coated surface.

[0129] In the preceding description, for purposes of explanation, numerous details are set forth in order to provide a thorough understanding of the embodiments of the invention. However, it will be apparent to one skilled in the art that these specific details are not
10 required in order to practice the invention.

[0130] The above-described embodiments of the invention are intended to be examples only. Alterations, modifications and variations can be effected to the particular embodiments by those of skill in the art without departing from the scope of the invention, which is defined solely by the claims appended hereto.

15

CLAIMS

What is claimed is:

1. A diluting agent for diluting viscous oil, the diluting agent comprising:
 - (a) an ether with 2 to 8 carbon atoms; and
 - 5 (b) a non-polar hydrocarbon with 2 to 30 carbon atoms.
2. The diluting agent according to claim 1, wherein (a) has 2 to 4 carbon atoms.
3. The diluting agent according to claim 1, wherein (a) is di-methyl ether, methyl ethyl ether, di-ethyl ether, methyl iso-propyl ether, methyl propyl ether, di-isopropyl ether, di-propyl ether, methyl iso-butyl ether, methyl butyl ether, ethyl iso-butyl ether, ethyl butyl ether, iso-
10 propyl butyl ether, propyl butyl ether, di-isobutyl ether, or di-butyl ether.
4. The diluting agent according to claim 1, wherein (a) is di-methyl ether.
5. The diluting agent according to claim 1, wherein (a) is di-ethyl ether.
6. The diluting agent according to claim 1, wherein (b) is a C2-C30 alkane.
7. The diluting agent according to claim 1, wherein (b) is a C2-C20 n-alkane.
- 15 8. The diluting agent according to claim 1, wherein (b) is a C2-C5 alkane.
9. The diluting agent according to claim 1, wherein (b) is propane.
10. The diluting agent according to claim 1, wherein (b) is a C5-C7 cycloalkane.
11. The diluting agent according to claim 1, wherein (b) is cyclohexane.
12. The diluting agent according to claim 1, wherein (b) is a mixture of non-polar
20 hydrocarbons, the non-polar hydrocarbons being C2-C30 alkanes, the mixture being substantially aliphatic and substantially non-halogenated.
13. The diluting agent according to claim 1, wherein (b) is a mixture of non-polar hydrocarbons and is a gas plant condensate comprising at least one C3-C17 n-alkane, at least one C5-C7 cycloalkane, and at least one C6-C8 aromatic hydrocarbon.
- 25 14. The diluting agent according to claim 1, wherein (a) is di-methyl ether and (b) is propane.
15. The diluting agent according to claim 1, wherein (b) has a hydrogen bonding parameter of less than 1 MPa^{0.5} and a polarity parameter of less than 1 MPa^{0.5}.
16. The diluting agent according to claim 1, wherein the diluting agent has a volume ratio
30 (a):(b) of 10:90 to 90:10.

17. The diluting agent according to claim 16, wherein the volume ratio is 20:80 to 70:30.
18. The diluting agent according to claim 16, wherein the volume ratio is 22.5:77.5 to 50:50.
- 5 19. The diluting agent according to claim 1, wherein the diluting agent has a viscosity of 0.2 to 5 cp at room temperature.
20. The diluting agent according to claim 1, wherein the diluting agent has a density of 450 to 750 kg/m³ at 15 °C.
21. The diluting agent according to claim 1, wherein the diluting agent is in liquid form.
- 10 22. The diluting agent according to claim 1, wherein the diluting agent has a Hansen hydrogen bonding solubility parameter of 0.7 to 6.2.
23. The diluting agent according to claim 1, wherein the diluting agent has a Hansen polar solubility parameter of 0.5 to 6.5.
24. A process for recovering viscous oil from an underground reservoir, the process
15 comprising:
- (i) injecting the diluting agent according to claim 1 into the reservoir to reduce the viscosity of the viscous oil; and
- (ii) producing at least a fraction of the diluting agent and the viscous oil.
25. The process of claim 24, wherein the process is a solvent-assisted steam-assisted
20 gravity drainage, a cyclic solvent dominated recovery process, a liquid addition to steam for enhanced recovery process, a vapour extraction process, or a heated solvent process.
26. The process according to claim 24, wherein the process is a cyclic solvent dominated recovery process.
27. A process for establishing fluid communication in an underground viscous oil
25 reservoir between injector and producer wells in a solvent assisted gravity drainage process prior to steam injection, the process comprising:
- (i) providing the diluting agent according to claim 1; and
- (ii) injecting the diluting agent into the reservoir to establish the fluid communication.
- 30 28. A process for diluting viscous oil at surface, the process comprising:
- (i) providing viscous oil; and

(ii) combining the diluting agent according to claim 1 with the viscous oil to dilute the viscous oil.

29. A process for cleaning a viscous oil-coated surface, the process comprising:

(i) providing the diluting agent according to claim 1; and

5 (ii) applying the diluting agent to the viscous oil-coated surface to clean the viscous oil-coated surface.

30. A use of the diluting agent according to claim 1, for diluting viscous oil.

31. The use according to claim 30, wherein the diluting viscous oil is *in-situ* dilution of the viscous oil within an underground viscous oil reservoir.

10 32. The use according to claim 30, wherein the use is for injecting the diluting agent into a well completed in the underground viscous oil reservoir to reduce a viscosity of the *in-situ* viscous oil.

33. The use according to claim 30, wherein the use is for *in-situ* viscous oil dilution by a solvent-assisted steam-assisted gravity drainage process, a cyclic solvent dominated
15 recovery process, a liquid addition to steam for enhanced recovery process, a vapour extraction process, or a heated solvent process.

34. The use according to claim 30, wherein the use is for *in-situ* viscous oil dilution by a cyclic solvent dominated recovery process.

35. The use according to claim 30, for establishing fluid communication in an
20 underground viscous oil reservoir between injector and producer wells in a solvent assisted gravity drainage process prior to steam injection.

36. The use according to claim 30, wherein the use of the diluting agent is together with steam.

37. The use according to claim 30, wherein the diluting viscous oil is surface dilution.

25 38. The use according to claim 37, wherein the diluting viscous oil is a solvent-based extraction process.

39. The use according to claim 30, for cleaning a viscous oil-coated surface.

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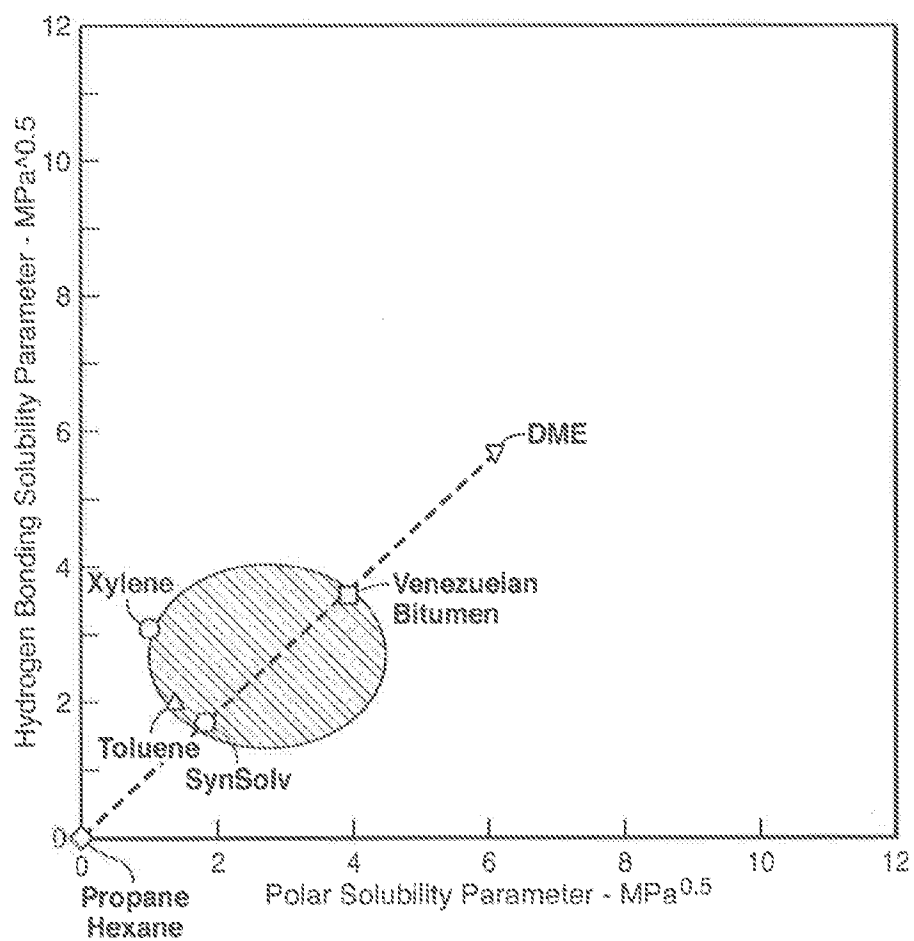


FIG. 1

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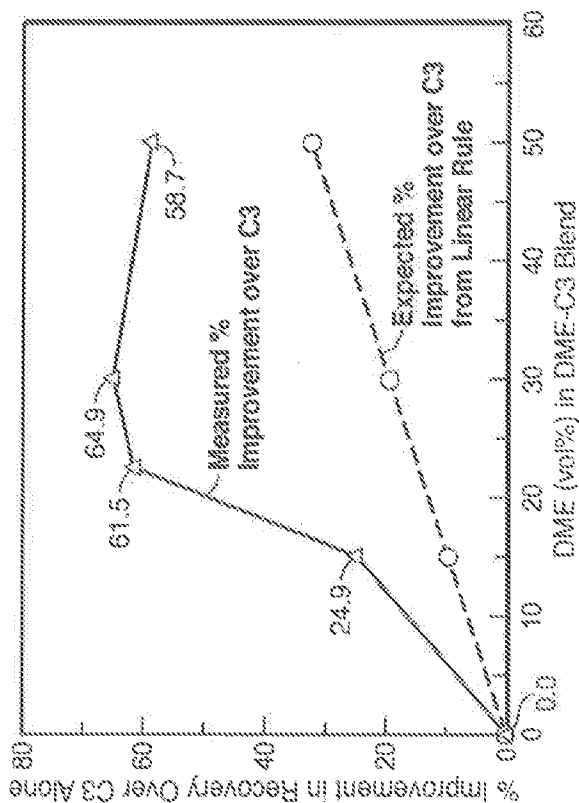


FIG. 3

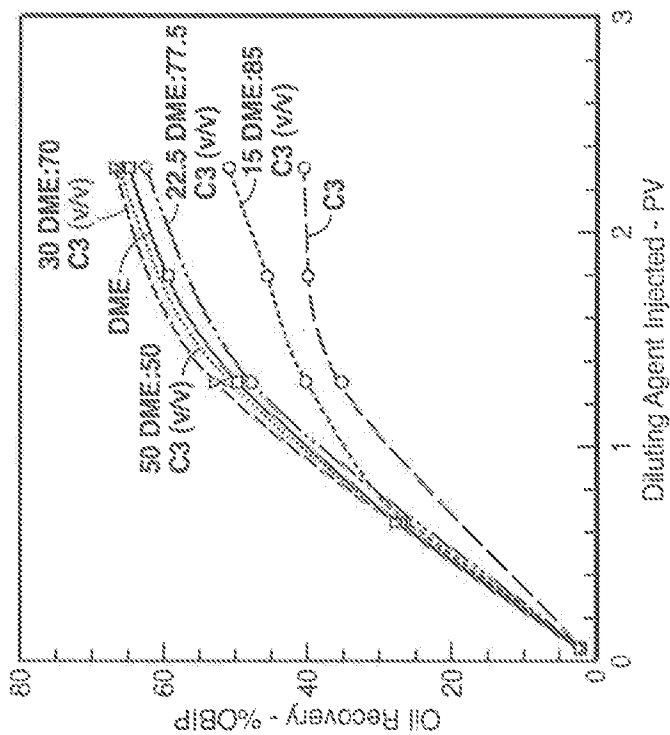


FIG. 2

INTERNATIONAL SEARCH REPORT

International application No.

PCT/US2013/042894

A. CLASSIFICATION OF SUBJECT MATTER

IPC(8) - C09K 8/58 (2013.01)

USPC - 166/270

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) - C09K 8/02, 8/035, 8/52, 8/524, 8/58, 8/592, 8/594; C10C 3/00; C10G 1/00; E21B 43/00, 43/16 (2013.01)

USPC - 166/270; 507/260

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

CPC - C09K 8/524, 8/58, 8/592, 8/594; C10G 1/04 (2013.01)

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

Orbit, Google Patents, Google Scholar

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	WO 2009/048701 A1 (KHARRAT) 16 April 2009 (16.04.2009) entire document	1-4, 6-9, 12, 14, 16-18, 21, 24, 30, 31

Y		5, 10, 11, 13, 15, 19, 20, 22, 23, 25-29, 32-39
Y	US 2012/0037363 A1 (CUROLE) 16 February 2012 (16.02.2012) entire document	5, 32
Y	WO 94/19575 A2 (THORSSSEN et al) 01 September 1994 (01.09.1994) entire document	10, 11, 13
Y	US 2008/0263781 A1 (DAMASO et al) 30 October 2008 (30.10.2008) entire document	15
Y	US 2010/0130386 A1 (CHAKRABARTY) 27 May 2010 (27.05.2010) entire document	19, 20, 22, 23, 25-29, 33-39

☐ Further documents are listed in the continuation of Box C.

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"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search

18 November 2013

Date of mailing of the international search report

27 NOV 2013

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:

Blaine R. Copenheaver

PCT Helpdesk: 571-272-4300

PCT OSP: 571-272-7774