SYSTEM AND METHOD FOR INTEGRATED ENHANCED OIL RECOVERY

Title

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ABSTRACT

The invention relates to systems and methods for enhanced oil recovery from an underground oil reservoir. In particular, an integrated system combining underground coal gasification product gas generation, production of higher hydrocarbons and enhanced oil recovery is disclosed. Also disclosed are methods for recovering a hydrocarbon-containing fluid form an oil reservoir.
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Invention Title: SYSTEM AND METHOD FOR INTEGRATED ENHANCED OIL RECOVERY

The invention is described in the following statement:
SYSTEM AND METHOD FOR INTEGRATED ENHANCED OIL RECOVERY

TECHNICAL FIELD

[0001] This invention relates to systems and methods for enhanced oil recovery from an underground oil reservoir integrated with underground coal gasification (UCG) product gas generation and production of higher hydrocarbons.

BACKGROUND ART

[0002] Typically, oil is produced using the natural pressure of an oil reservoir to force the oil into a well bore where it is brought to the surface by natural pressure or with pumping methods. After some period of production, the natural pressure of the oil reservoir decreases and production dwindles. In conventional light oil reservoirs, secondary recovery methods can be used to recover additional oil by utilising injected water or hydrocarbon gases (e.g., natural gas, ethane, butane, and propane) are used to drive the oil to the well bore prior to pumping it to the surface. In heavy oil and oil sands reservoirs, steam may be injected into the reservoir to reduce the viscosity of the oil and enable it to flow to production wells and be pumped to surface.

[0003] Once primary and secondary production has occurred, producers may turn to tertiary or enhanced oil recovery (EOR) techniques. One known EOR technique is high-pressure CO$_2$ injection, which helps to repressurise the oil reservoir. The high-pressure CO$_2$ also acts as a solvent, dissolving the residual oil, thereby reducing its viscosity and improving its flow characteristics, allowing it to be pumped out of an aging reservoir.

[0004] One difficulty with the use of CO$_2$ to increase oil production is that it requires large quantities of CO$_2$, and the availability of such large quantities of CO$_2$ is often limited in the vicinity of the oil reservoirs.

[0005] The demand for CO$_2$ for use in CO$_2$-EOR projects in the USA alone is projected to be over 12 billion metric tons. Most of this forecast demand is for use
onshore in the lower-48 states, in particular in states such as Texas and Wyoming. A significant demand is also forecast in Alaska (Ferguson et al., "Storing CO₂ With Next-Generation CO₂-EOR Technology", SPE International Conference on CO₂ Capture, Storage, and Utilization, 10-12 November 2010, New Orleans, Louisiana, USA).

[0006] Heavy oil and oil sands have poor mobility at standard reservoir conditions, because the viscosity of the oil or bitumen is so low. In order to produce these hydrocarbons, they are normally heated so that the viscosity is reduced to a point that allows the hydrocarbons to flow. Heat can be added to the reservoir in a variety of ways, including in-situ heating, in-situ combustion and other methods. The most popular method of heating the formations is to add steam to the reservoir. In addition, gas helps dissolve into the heavy oil, reducing its viscosity (with or without temperature). Therefore, steam and CO₂ (as well as N₂) can be useful for improving heavy oil production, particularly if available hot inside the reservoir.

[0007] Accordingly, as recognised by the present inventor, what is needed are new systems and methods for extracting oil from aging reservoirs and from deep heavy oil reservoirs, where existing methods are not very effective.

SUMMARY OF INVENTION

[0008] Underground coal gasification is a process by which product gas is produced from a coal seam by combusting and gasifying the coal in situ in the presence of an oxidant. The product gas is typically referred to as synthesis gas or syngas and can be used as a feedstock for various applications, including clean fuels production, chemical production, and electricity generation.

[0009] Wells are drilled into the coal seam to allow for oxidant injection and product gas extraction. The wells are linked or extended to form an in-seam well channel to facilitate oxidant injection, cavity development, and product gas flow at rates which enable economic conversion and extraction of the energy in the coal.
The well allowing the injection of oxidant is called an injection well. The well from which product gas emerges is called a production well. Both horizontal and vertical well regions can be used for injection and production. Underground coal gasification can also utilise one or more vertical wells (service wells) located between the injection and production wells.

A coal seam having an in-seam well channel is typically referred to as a coal gasifier. The gasifier will have a combustion zone within which coal is combusted in the presence of an oxidant, a gasification zone located downstream of the combustion zone in which coal is gasified and partially oxidized to produce product gas, and a downstream pyrolysis zone in which pyrolysis of coal occurs. Hot product gas flows downstream from the gasification zone and exits the ground from a well head of the production well. As coal is consumed or gasified, a gasifier (gasification) cavity within the coal seam develops and grows in size.

Typically, UCG product gas will contain: (1) main syngas components (e.g., CO, H₂, CO₂, N₂, and CH₄); (2) solid particles/particulates (e.g., soot, ash, and coal particles); (3) water; (4) minor components such as C₂-C₆ hydrocarbons, oxygen, argon, sulphur containing components (e.g., H₂S, COS, CS₂, mercaptans, and thiophenes), nitrogen based components (e.g., NH₃ and HCN), hydrocarbon components (e.g., coal condensate, BTEX (benzene, toluene, ethylbenzene and xylenes), and PAHs (polycyclic aromatic hydrocarbons)); and (5) trace components such as heavy metals (arsenic and mercury) and chlorides.

It is an object of the present invention to provide systems and methods for extracting oil from aging reservoirs integrated with UCG product gas generation and production of higher hydrocarbons.

In one aspect, the invention provides an integrated system for providing gas and liquid for injection in an oil reservoir for recovery of a hydrocarbon-containing fluid and production of higher hydrocarbons from underground coal, including (a) an air separation unit for production of oxygen and nitrogen, (b) an underground coal gasifier adapted to produce an in situ syngas including H₂, CO, CH₄, CO₂, and H₂O, (c) a syngas clean-up facility adapted to remove and recover contaminants and CO₂.
from the syngas, (d) a syngas conditioning unit adapted to adjust the ratio of H₂ to CO in the syngas, (e) a synthesis unit adapted to synthesise a product from the syngas, and (f) an injection well in fluid communication with the oil reservoir, the injection well adapted to inject one or more of the following into the oil reservoir (i) nitrogen from the air separation unit, (ii) CO₂ from the syngas clean-up facility, (iii) a waste stream from the synthesis unit, (iv) water, and (v) steam.

[0015] In another aspect, the invention provides an integrated system for providing gas and liquid for injection in an oil reservoir for recovery of a hydrocarbon-containing fluid and production of higher hydrocarbons from underground coal, including (a) an air compression unit, (b) an underground coal gasifier adapted to produce an in situ syngas including H₂, CO, CH₄, CO₂, and H₂O, (c) a syngas clean-up facility adapted to remove and recover contaminants and CO₂ from the syngas, (d) a syngas conditioning unit adapted to adjust the ratio of H₂ to CO in the syngas, (e) a synthesis unit adapted to synthesise a product from the syngas, and (f) an injection well in fluid communication with the oil reservoir, the injection well adapted to inject one or more of the following into the oil reservoir (i) CO₂ from the syngas clean-up facility, (ii) a waste stream from the synthesis unit, (iii) water, and (iv) steam.

[0016] In some embodiments, the synthesis unit adapted to synthesise a product from the syngas is adapted to synthesise ammonia, methanol, and/or oxo alcohols.

[0017] In other embodiments, the synthesis unit adapted to synthesise a product from the syngas is a Fischer-Tropsch synthesis unit adapted to synthesise higher hydrocarbons from the syngas.

[0018] In yet another aspect, the invention provides a method for providing gas and liquid for injection in an oil reservoir for recovery of a hydrocarbon-containing fluid and production of higher hydrocarbons from underground coal, including the steps of (a) separating air into an oxygen-rich fraction and a nitrogen-rich fraction, (b) recombining a portion of the oxygen-rich fraction with a portion of the nitrogen-rich fraction to produce an oxidant having a desired oxygen concentration, (c) injecting the oxidant into an underground coal gasifier to produce an in situ syngas including H₂, CO, CH₄, CO₂, and H₂O, (d) removing contaminants and CO₂ from the syngas,
(e) recovering the CO₂, (f) synthesising a product from the syngas, (g) injecting one or more of (i) nitrogen from the nitrogen-rich fraction, (ii) the recovered CO₂, (iii) a waste stream from the synthesis of the product, (iv) water, and (v) steam into an injection well in fluid communication with the oil reservoir, and (h) recovering oil from the oil reservoir.

[0019] In a further aspect, the invention provides a method for providing gas and liquid for injection in an oil reservoir for recovery of a hydrocarbon-containing fluid and production of higher hydrocarbons from underground coal, including the steps of (a) compressing air for use as an oxidant, (b) injecting the oxidant into an underground coal gasifier to produce an in situ syngas including H₂, CO, CH₄, CO₂, and H₂O, (c) removing contaminants and CO₂ from the syngas, (d) recovering the CO₂, (e) synthesising a product from the syngas, (f) injecting one or more of (i) the recovered CO₂, (ii) a waste stream from the synthesis of the product, (iii) water, and (iv) steam into an injection well in fluid communication with the oil reservoir, and (g) recovering oil from the oil reservoir.

[0020] In some embodiments, water, steam and/or CO₂ are injected into the underground coal gasifier along with the oxidant.

[0021] In other embodiments, the methods further include the step of conditioning the syngas to adjust the ratio of H₂ to CO in the syngas.

[0022] In yet other embodiments, the methods further include the step of separating the injected CO₂ from the recovered oil. Suitably, the separated CO₂ is injected into the oil reservoir.

[0023] In another aspect, the invention provides a method for recovering a hydrocarbon-containing fluid from an oil reservoir, including the steps of (a) operating an underground coal gasifier at a pressure of greater than or equal to 80 bar to produce a CO₂- and CH₄-rich driver gas with minimal CO and H₂, (b) compressing the driver gas to an appropriate pressure for injection into the oil reservoir, (c) injecting the driver gas into the oil reservoir, and (d) recovering oil from the oil reservoir.
[0024] In one embodiment, the method further includes the step of introducing a methanation catalyst into the underground coal gasifier to promote methanation of the CO and H₂ in the driver gas to increase the concentration of CH₄ in the driver gas within the gasifier.

[0025] In another embodiment, the method further includes the steps of shifting the CO content of the CO₂⁻ and CH₄-rich driver gas to H₂ and removing the H₂ from the driver gas prior to injection into the oil reservoir. The shifting of the CO content via the water-gas shift reaction can be conducted within the underground gasifier, or within a dedicated shift reactor at the surface. The H₂ can also be removed from the driver gas prior to injection into the oil reservoir without the added shifting step.

[0026] In yet another embodiment, the method further includes the step of removing contaminants and/or higher hydrocarbons from the CO₂⁻ and CH₄-rich driver gas.

[0027] The CO₂⁻ and CH₄-rich driver gas can be compressed to a pressure appropriate for miscible displacement of oil from the oil reservoir (e.g., a pressure typically in the range of about 150 to 350 bar).

[0028] In still another embodiment, the method further includes the step of separating the injected CO₂ and CH₄ (and any associated gaseous products) from the recovered oil. The CO₂ can be separated from the CH₄, compressed to an appropriate pressure for injection into the oil reservoir and injected into the oil reservoir. Suitably, the separated CO₂ is compressed to a pressure appropriate for miscible displacement of oil from the oil reservoir (e.g., a pressure in the range of about 110 to 140 bar).

[0029] In another embodiment, the method further includes the steps of injecting the CO₂⁻ and CH₄-rich driver gas into a non-active cavity of the underground coal gasifier having a temperature of about 250 to about 450 °C, and recovering the driver gas for compression and injection into the oil reservoir. The purpose of this step is to further reduce the CO and H₂ content of the driver gas to increase the concentration of CO₂ and CH₄ via water-gas shift, methanation and hydrogasification reactions.
[0030] In yet another aspect, the invention provides a method for recovering a hydrocarbon-containing fluid from an oil reservoir, including the steps of (a) operating an underground coal gasifier to produce a syngas comprising $H_2$, CO, CH₄, and $H_2O$, (b) combusting the syngas with an oxidant to generate predominantly CO₂ and steam, (c) injecting the CO₂ and steam into the oil reservoir, and (d) recovering oil from the oil reservoir.

[0031] In one embodiment, the underground coal gasifier is operated at a pressure of greater than or equal to 80 bar.

[0032] The syngas can be combusted with an oxidant in a surface furnace or in a downhole generator. The oxidant can be air, enriched air, or oxygen mixed with water, steam and/or CO₂.

[0033] In some embodiments, the recovered oil is a heavy oil.

[0034] In other embodiments, the oil reservoir includes oil sands.

[0035] In order that the invention may be more readily understood and put into practice, one or more preferred embodiments thereof will now be described, by way of example only, with reference to the accompanying figures.

**BRIEF DESCRIPTION OF DRAWINGS**

[0036] Figure 1 is a diagram of an embodiment of an integrated system and process for underground coal gasification and enhanced oil recovery in accordance with the present invention.

[0037] Figure 2 is a diagram of an embodiment of an integrated process for underground coal gasification and enhanced oil recovery in accordance with the present invention.
Figure 3 is a diagram of an alternate embodiment of an integrated process for underground coal gasification and enhanced oil recovery in accordance with the present invention.

DESCRIPTION OF EMBODIMENTS

The present invention relates to integrating UCG product gas generation with EOR processes, including reservoir pressure maintenance, immiscible displacement, and/or miscible displacement. As will be understood by those of ordinary skill in the art, UCG product gas generation and EOR integration is facilitated by having an underground coal gasifier and an oil reservoir (and any necessary associated facilities) in relatively close proximity to one another. Where the underground coal gasifier is not located within the immediate vicinity of the oil reservoir, one or more pipelines can link various aspects of an integrated UCG and EOR system/process.

Throughout this specification, unless the context requires otherwise, the words “comprise”, “comprises” and “comprising” will be understood to mean the inclusion of a stated integer, group of integers, step, or steps, but not the exclusion of any other integer, group of integers, step, or steps.

The use of “a” or “an” to describe the various elements and components of the invention is merely for convenience and to give a general sense of the disclosure. This description should be read to include one or at least one of the various elements and components recited, and the singular also includes the plural unless it is obvious that it is meant otherwise.

When an amount, concentration, or other value or parameter is given as a range, or a list of upper and lower values, this is to be understood as specifically disclosing all ranges formed from any pair of any upper and lower range limits, regardless of whether these ranges are separately disclosed. Where a range of numerical values is recited herein, unless otherwise stated, the range is intended to include the endpoints thereof, and all integers and fractions within the range. It is not
intended that the scope of the present disclosure be limited to the specific values recited when defining a range.

[0043] When the term “about” is used in describing a value or an end-point of a range, the disclosure should be understood to include the specific value or end-point referred to.

[0044] As used herein, the term “predominant portion” means greater than about 50% of the referenced material. The percent is on a molar basis when reference is made to a molecule (e.g., H₂, CH₄, CO₂, CO, and H₂S), and otherwise is on a weight basis (e.g., the liquid component of a hydrocarbon-containing fluid).

[0045] As used herein, the term “substantial portion” means greater than about 90% of the referenced material, preferably greater than about 95% of the referenced material, and more preferably greater than about 97% of the referenced material. The percent is on a molar basis when reference is made to a molecule (e.g., H₂, CH₄, CO₂, CO, and H₂S), and otherwise is on a weight basis (e.g., the liquid component of a hydrocarbon-containing fluid).

[0046] The term “unit” refers to a unit operation as used herein. When more than one “unit” is described as being present, those units are operated in a parallel fashion. A single “unit”, however, can include more than one of the units in series, or in parallel, depending on the context. For example, an acid gas removal unit can include a H₂S removal unit followed in series by a CO₂ removal unit. As another example, a contaminant removal unit can include a first removal unit for a first contaminant followed in series by a second removal unit for a second contaminant.

[0047] In one aspect, the invention provides an integrated system for providing gas and liquid for injection in an oil reservoir for recovery of a hydrocarbon-containing fluid and production of higher hydrocarbons from underground coal, including (a) an air separation unit for production of oxygen and nitrogen, (b) an underground coal gasifier adapted to produce an in situ syngas including H₂, CO, CH₄, CO₂, and H₂O, (c) a syngas clean-up facility adapted to remove and recover contaminants and CO₂ from the syngas, (d) a syngas conditioning unit adapted to adjust the ratio of H₂ to
CO in the syngas, (e) a synthesis unit adapted to synthesise a product from the syngas, and (f) an injection well in fluid communication with the oil reservoir, the injection well adapted to inject one or more of the following into the oil reservoir (i) nitrogen from the air separation unit, (ii) CO₂ from the syngas clean-up facility, (iii) a waste stream from the synthesis unit, (iv) water, and (v) steam.

[0048] In another aspect, the invention provides an integrated system for providing gas and liquid for injection in an oil reservoir for recovery of a hydrocarbon-containing fluid and production of higher hydrocarbons from underground coal, including (a) an air compression unit, (b) an underground coal gasifier adapted to produce an in situ syngas including H₂, CO, CH₄, CO₂, and H₂O, (c) a syngas clean-up facility adapted to remove and recover contaminants and CO₂ from the syngas, (d) a syngas conditioning unit adapted to adjust the ratio of H₂ to CO in the syngas, (e) a synthesis unit adapted to synthesise a product from the syngas, and (f) an injection well in fluid communication with the oil reservoir, the injection well adapted to inject one or more of the following into the oil reservoir (i) CO₂ from the syngas clean-up facility, (ii) a waste stream from the synthesis unit, (iii) water, and (iv) steam.

[0049] In yet another aspect, the invention provides a method for providing gas and liquid for injection in an oil reservoir for recovery of a hydrocarbon-containing fluid and production of higher hydrocarbons from underground coal, including the steps of (a) separating air into an oxygen-rich fraction and a nitrogen-rich fraction, (b) recombining a portion of the oxygen-rich fraction with a portion of the nitrogen-rich fraction to produce an oxidant having a desired oxygen concentration, (c) injecting the oxidant into an underground coal gasifier to produce an in situ syngas including H₂, CO, CH₄, CO₂, and H₂O, (d) removing contaminants and CO₂ from the syngas, (e) recovering the CO₂, (f) synthesising a product from the syngas, (g) injecting one or more of (i) nitrogen from the nitrogen-rich fraction, (ii) the recovered CO₂, (iii) a waste stream from the synthesis of the product, (iv) water, and (v) steam into an injection well in fluid communication with the oil reservoir, and (h) recovering oil from the oil reservoir.
In a further aspect, the invention provides a method for providing gas and liquid for injection in an oil reservoir for recovery of a hydrocarbon-containing fluid and production of higher hydrocarbons from underground coal, including the steps of (a) compressing air for use as an oxidant, (b) injecting the oxidant into an underground coal gasifier to produce an in situ syngas including H₂, CO, CH₄, CO₂, and H₂O, (c) removing contaminants and CO₂ from the syngas, (d) recovering the CO₂, (e) synthesising a product from the syngas, (f) injecting one or more of (i) the recovered CO₂, (ii) a waste stream from the synthesis of the product, (iii) water, and (iv) steam into an injection well in fluid communication with the oil reservoir, and (g) recovering oil from the oil reservoir.

As used herein, the term "hydrocarbon-containing fluid" means a fluid including any hydrocarbon liquid and/or gas. A hydrocarbon-containing fluid can also include solid particles. Oil, gas-condensate and the like, and also their mixtures with other liquids, such as water, are examples of a liquid contained in a hydrocarbon-containing fluid. Any gaseous hydrocarbon (e.g., CH₄, C₂H₆, C₃H₈, C₄H₁₀, or the like), and mixtures of gaseous hydrocarbons, can be contained in a hydrocarbon-containing fluid. In the context of the present invention, the hydrocarbon-containing fluid is recovered from an underground hydrocarbon reservoir, such as an oil-bearing formation, a gas-condensate reservoir, a natural gas reservoir, and the like.

The air separation unit (ASU) for separating air into an oxygen-rich fraction and a nitrogen-rich fraction can be of any suitable size, shape and construction, as is well known to those of ordinary skill in the art. Preferably, the ASU produces both nitrogen and oxygen with a high purity. Typically, the produced nitrogen will have a purity of greater than 99.9%, while the produced oxygen will have a purity of about 98 to 99.5%.

The oxidant used for underground coal gasification is preferably air (approximately 20% oxygen), oxygen-enriched air (greater than 20% oxygen), or a gas/gas mixture (e.g., CO₂ and/or nitrogen in any desired ratio) enriched with oxygen (greater than 20% oxygen), or substantially pure oxygen. The oxidant source can
include an air compressor, a tank/cylinder of compressed air or oxygen, an ASU, or a tank/cylinder of liquid oxygen, for example.

[0054] The oxidant can be injected into an underground coal gasifier to produce an in situ syngas in a conventional manner.

[0055] Optionally, water or steam can also be injected into the underground coal gasifier, as well as other gases, such as CO₂ and/or nitrogen.

[0056] The CO₂ for injection into the underground coal gasifier can be recycled from a downstream processing/clean-up facility that separates CO₂ from syngas. The water can be obtained from a naturally occurring water source, such as surface water or ground water. The water can be either fresh water or brine. The water can be treated water, such as demineralised water or raw water separated from syngas.

[0057] The raw syngas produced in situ in an underground coal gasifier includes H₂, CO, CH₄, and CO₂. The actual composition of the produced syngas will depend on the UCG process (including underground carbonaceous feedstock) utilised to generate the syngas.

[0058] The raw syngas can also contain other gaseous components such as, for example, steam, H₂S, sulphur oxides, nitrogen oxides, and other gaseous hydrocarbons, again, depending on the UCG process and the underground carbonaceous feedstock.

[0059] As is well known to those of ordinary skill in the art, the contamination levels of the raw syngas will depend on the nature of the underground carbonaceous feedstock and the UCG process conditions. For example, certain coals have high sulphur contents, leading to higher sulphur oxides (SOₓ), H₂S and/or COS contamination. Certain coals contain significant levels of mercury, which can be volatilized during the UCG process. Other coals are high in nitrogen content, leading to ammonia, nitrogen oxides (NOₓ) and/or cyanides.

[0060] In addition, raw syngas typically contains entrained particulates.
Some of these contaminants are typically removed in an acid gas removal unit, such as \( \text{H}_2\text{S} \) and \( \text{COS} \). Others, such as ammonia and mercury, typically require removal prior to acid gas removal.

Any suitable type of filtration process for removal of entrained particulates can be employed. For example, particulate removal can be done in two stages; the first stage for removal of larger particles, and the second stage for removal of very fine particulates that remain in the syngas after the first stage.

As will be known by those of ordinary skill in the art, suitable particulate removal systems include hot candle filters (for removal of particulates as a dry solid), water scrubbers (for removal of particulates as a slurry), electrostatic precipitators, and separators, such as cyclone separators and cyclone separators employing water scrubbers. Preferably, the filtration process will reduce the particulate content of the syngas to a level below about 1 mg/Nm\(^3\), but the actual required level will depend on the intended use for the treated syngas, and can be ascertained by those of ordinary skill in the art.

Examples of a suitable dehydration unit for reduction of water in raw or treated syngas include a knock-out drum or similar water separation device, and/or water absorption processes, such as glycol treatment.

When present, contaminant removal of a particular contaminant should remove at least a substantial portion of that contaminant from the treated, cleaned syngas stream, typically to levels at or lower than the specification limits for the desired treatment unit, or the desired end product.

Contaminant removal processes and units/facilities are, in a general sense, well known to those of ordinary skill in the art.

A raw syngas stream exiting an underground coal gasifier will often be of a temperature higher than suitable for feeding downstream gas processes (e.g., an acid gas removal unit), so upon exit from a production well the syngas stream can be passed through a heat exchanger unit to remove heat energy and generate a cooled
syngas stream. The heat energy recovered in the heat exchanger unit can be used to generate steam and/or superheat various process streams, as will be recognised by those of ordinary skill in the art. Any steam generated can be used, for example, for internal process requirements and/or to generate electrical power.

[0068] Carbon dioxide is typically removed from a syngas stream in an acid gas removal unit (along with H₂S if present), generating a CO₂-rich stream (in some instances a sour CO₂-rich stream) and an acid gas-depleted syngas stream.

[0069] Acid gas removal processes typically involve contacting a syngas stream with a solvent, such as monoethanolamine, diethanolamine, methyl diethanolamine (MDEA), diisopropylamine, diglycolamine, a solution of sodium salts of amino acids, methanol, hot potassium carbonate, or the like to generate CO₂ and/or H₂S laden absorbers. Well known methods involve the use of Selexol ® or Rectisol ® solvent having two trains, each train containing an H₂S absorber and a CO₂ absorber.

[0070] At least a substantial portion of the CO₂ and/or H₂S (and other remaining trace contaminants) should be removed via the acid gas removal processes. "Substantial" removal in the context of acid gas removal means removal of a high enough percentage of the component such that a desired end product can be generated. The actual amounts of removal can thus vary from component to component. Desirably, only trace amounts of H₂S should be present in the acid gas-depleted product stream, although higher amounts of CO₂ may be tolerable depending on the desired end product.

[0071] Typically, at least about 85%, or at least about 90%, or at least about 95%, of the CO₂, and at least about 95%, or at least about 98%, or at least about 99.5%, of the H₂S, should be removed from the syngas stream, based on the amount of those components contained in the raw/treated syngas fed to the acid gas removal unit.

[0072] In applications where very low sulphur (e.g., less than about 10 ppm) syngas is required, converting carbonyl sulphide (COS) to H₂S before sulphur removal may also be necessary. As is well known to those of ordinary skill in the art,
this is done by passing the sulphur-containing syngas through a catalytic hydrolysis reactor, where over 99% of the COS is converted to H₂S.

[0073] Any recovered H₂S from the acid gas removal can be converted to elemental sulphur by any method known to those of ordinary skill in the art, including the Claus process.

[0074] In certain embodiments, particularly where a syngas stream contains appreciable amounts of CO, and it is desired to maximise H₂ and/or CO₂ production, all or a part of such a syngas stream can be supplied to a water-gas shift reactor for conversion of CO to H₂ and CO₂ according to the reaction:

\[
\text{CO} + \text{H}_2\text{O} \rightarrow \text{H}_2 + \text{CO}_2
\]

[0075] In a water-gas shift reactor, gases undergo a water-gas shift reaction (also known as a sour shift reaction) in the presence of an aqueous medium (such as steam) to convert a predominant portion (or a substantial portion) of the CO to CO₂, which also increases the fraction of H₂, producing a hydrogen-enriched stream.

[0076] Methods and reactors for performing the water-gas shift reaction on a CO-containing syngas stream are well known to those of ordinary skill in the art. Suitable reaction conditions and suitable reactors can vary depending on the amount of CO that must be depleted from the syngas stream. In some embodiments, the water-gas shift can be performed in a single stage within a temperature range from about 100 °C, or from about 150 °C, or from about 200 °C, to about 250 °C, or to about 300 °C, or to about 350 °C. In these embodiments, the shift reaction can be catalysed by any suitable catalyst known to those of ordinary skill in the art. Such catalysts include, but are not limited to, Fe₂O₃-based catalysts, such as Fe₂O₃-Cr₂O₃ catalysts, and other transition metal-based and transition metal oxide-based catalysts.

[0077] In other embodiments, the water-gas shift can be performed in multiple stages. In one particular embodiment, the water-gas shift is performed in two stages. This two-stage process uses a high-temperature sequence followed by a low-temperature sequence. The gas temperature for the high-temperature shift reaction
ranges from about 350 °C to about 500 °C. Typical high-temperature catalysts include, but are not limited to, iron oxide optionally combined with lesser amounts of chromium oxide. The gas temperature for the low-temperature shift ranges from about 150 °C to about 300 °C, or from about 200 °C to about 250 °C. Low-temperature shift catalysts include, but are not limited to, copper oxides that may be supported on zinc oxide or alumina.

[0078] Hydrogen can be separated from a syngas stream (e.g., a hydrogen-enriched syngas stream) according to methods known to those of ordinary skill in the art, such as cryogenic distillation, the use of molecular sieves, gas separation membranes (e.g., ceramic or polymeric), and/or pressure swing adsorption (PSA) techniques.

[0079] The recovered H₂ can be used, for example, as an energy source and/or as a reactant. For example, the recovered H₂ can be used as an energy source for hydrogen-based fuel cells, or for power and/or steam generation via combustion in a power generation block. The recovered H₂ can also be used as a reactant in various hydrogenation processes, such as found in the chemical and petroleum refining industries.

[0080] Treated syngas can be used as a feedstock in a synthesis unit for the production of one or more desired products, including, but not limited to, ammonia, methanol, oxo alcohols, and higher hydrocarbons.

[0081] Synthesis processes and units/facilities are, in a general sense, well known to those of ordinary skill in the art. For example, well known Fischer-Tropsch synthesis can be used to synthesise higher hydrocarbons for synthetic fuel production.

[0082] As disclosed herein, one or more of nitrogen from an ASU, CO₂ from syngas clean-up, a waste stream from a synthesis process, unit and/or facility, water, and steam can be injected into an oil reservoir via one or more injection wells utilising techniques well known to those of ordinary skill in the art for recovery of a hydrocarbon-containing fluid (including, for example, oil). A preferred injectant is CO₂.
Suitable compressors for compressing a gas to appropriate pressures and conditions for EOR are well-known to those of ordinary skill in the art. A compressor can include a first compressor to compress a stream to a first pressure, followed in series by a second compressor to further compress the stream to a second (higher) pressure.

The injected fluid (e.g., in a supercritical fluid state), gas or fluid/gas combination serves to enhance production of a hydrocarbon-containing fluid from a production well through a combination of mechanisms typically involving repressurisation of the underground reservoir and viscosity reduction of the trapped hydrocarbon (improving flow properties).

Typical minimum miscibility pressures for a variety of gases are shown in Table 1, below.

<table>
<thead>
<tr>
<th>Minimum miscibility pressures</th>
</tr>
</thead>
<tbody>
<tr>
<td>MMP (bar)</td>
</tr>
<tr>
<td>CO₂</td>
</tr>
<tr>
<td>CH₄</td>
</tr>
<tr>
<td>Air</td>
</tr>
<tr>
<td>N₂</td>
</tr>
<tr>
<td>CO</td>
</tr>
<tr>
<td>H₂</td>
</tr>
</tbody>
</table>

Carbon dioxide-based EOR can also involve co-injection (both at the same time in the same location), concurrent injection (both at the same time at different locations), consecutive, or alternating injection (one followed by the other in the same or separate locations), or some combination of these various techniques, of pressurised nitrogen, water, steam, and/or other fluids (e.g., excess hydrocarbons).

The resulting hydrocarbon-containing fluid is produced and recovered through one or more hydrocarbon production wells. The produced hydrocarbon-containing fluid will typically contain liquid and gas hydrocarbon components, as well
as other liquid and gaseous components, depending on the oil reservoir and EOR conditions. The liquid hydrocarbon component can generally be considered as a crude oil, while the gaseous hydrocarbon component will typically include hydrocarbons that are gases at ambient conditions, such as CH₄, C₂H₆, C₃H₈, and C₄H₁₀. Other typical liquid components include water or brine. The hydrocarbon-containing fluid can also include CO₂, H₂S and/or nitrogen. The hydrocarbon-containing fluid can also include solid carbon and mineral matter.

[0088] The produced hydrocarbon-containing fluid can be passed to a separation unit to separate the gaseous components from the liquid/solid components to generate a gaseous hydrocarbon product stream, a liquid hydrocarbon product stream and, optionally, a stream containing solids components from the hydrocarbon-containing fluid. The solids can also optionally be carried with the liquid hydrocarbon product stream for later separation, or separated out prior to the separation unit, by well-known techniques, such as settling, centrifugation and/or filtration. In one embodiment, larger/denser solids are separated in conjunction with the separation unit, and finer solids that may become entrained in the liquid hydrocarbon product stream are separated subsequently through well-known techniques, such as filtration.

[0089] Suitable separation units for separating gaseous components from liquid/solid components are well known to those of ordinary skill in the art, and include, for example, single and multistage horizontal separators and cyclones.

[0090] The liquid hydrocarbon product stream will typically include at least a predominant portion (or a substantial portion) of the liquid components from the hydrocarbon-containing fluid, including, for example, crude oil and water/brine. The liquid hydrocarbon product stream can subsequently be processed to separate out the water and other contaminants, then further processed (e.g., refined) to a variety of end products or for a variety of end uses, as is well-known to those of ordinary skill in the art.

[0091] If a stream containing solids components is present, it will typically be removed from the separation unit as a concentrated slurry or with some portion of the liquid content of the hydrocarbon-containing fluid. Oil that may be withdrawn with the
solids can be recovered from the solids via washing or other techniques well-known to those of ordinary skill in the art.

[0092] The resulting gaseous hydrocarbon product stream exiting the separation unit typically includes at least a substantial portion of the gaseous components from the hydrocarbon-containing fluid, including at least a substantial portion of the gaseous hydrocarbons (and CO₂ to the extent present) from the produced hydrocarbon-containing fluid. The gaseous hydrocarbon product stream can also include minor amounts of water vapour (which can be substantially removed prior to further treatment, for example, in an acid gas removal unit as discussed herein) as well as other contaminants if present, such as H₂S.

[0093] If the produced hydrocarbon-containing fluid contains more than trace amounts of acid gases, such as CO₂ and/or H₂S, the resulting gaseous hydrocarbon product stream will contain a substantial portion of the acid gases, and can be subjected to acid gas removal to remove and recover the acid gases.

[0094] All or a portion of the gaseous hydrocarbon product stream exiting the separation unit can be combined with the syngas stream or otherwise co-processed with the syngas stream in the acid gas removal unit as described herein. For example, if the gaseous hydrocarbon product stream includes more than a trace amount of H₂S, the gaseous hydrocarbon product stream can be combined with the syngas stream or otherwise co-processed with the syngas stream in the acid gas removal unit as discussed herein.

[0095] Likewise, all or a portion of the gaseous hydrocarbon product stream exiting the separation unit can be combined with the syngas stream or otherwise co-processed with the syngas stream in the water-gas shift reactor (followed by H₂ separation if desired) as described herein.

[0096] Prior to combination with the syngas stream or co-processing in the acid gas removal unit and/or water-gas shift reactor, the gaseous hydrocarbon product stream can optionally be compressed and/or heated to pressure and temperature
conditions suitable for combination or other downstream processing as described herein.

[0097] All or a portion of the gaseous hydrocarbon product stream can, in addition or alternatively, be combusted in a power generation block, for example, for electrical power and/or steam generation.

[0098] Carbon dioxide recovered from the produced hydrocarbon-containing fluid can be injected into the oil reservoir for further EOR.

[0099] In another aspect, the invention provides a method for recovering a hydrocarbon-containing fluid from an oil reservoir, including the steps of (a) operating an underground coal gasifier at a pressure of greater than or equal to 80 bar to produce a CO₂- and CH₄-rich driver gas with minimal CO and H₂, (b) compressing the driver gas to an appropriate pressure for injection into the oil reservoir, (c) injecting the driver gas into the oil reservoir, and (d) recovering oil from the oil reservoir.

[0100] As shown in Table 1, the MMP of CH₄ is favourable for miscible displacement of oil. Operating an underground coal gasifier at a high pressure (i.e., greater than or equal to 50 bar) favours the in situ formation of CH₄ from produced CO. In practice, an underground coal gasifier can routinely be operated at a pressure of about 50 to 200 bar, well in excess of the pressures that are typically used in surface coal gasifiers.

[0101] Operating an underground coal gasifier at a pressure of greater than or equal to 80 bar results in a CO₂- and CH₄-rich driver gas with minimal CO and H₂. By “minimal CO and H₂” is intended CO and H₂ levels typically less than 7 mol% each in the driver gas.

[0102] For miscible EOR, this means that the resultant UCG product gas has a high proportion of CO₂ and CH₄ and small concentrations of CO and H₂. The N₂ content should also be low. To achieve such product gas quality, it is preferred to operate the underground coal gasifier at very high pressures, where much of the
primary H₂ produced in the gasifier is converted to CH₄. When pressures are above 80 bar, then the quantities of CO and H₂ are much smaller than when a low pressure UCG process is used.

[0103] If the CO content is significant (i.e., greater than 7 mol%) then the CO can be shifted to H₂ and removed. If the H₂ content is significant (i.e., greater than 7 mol%) it is desirable to remove the H₂ from the syngas prior to injection into an oil reservoir. The exact levels at which conversion of CO and removal of H₂ are required will depend on the properties of the oil reservoir, in particular the MMP of the syngas/oil mixture. For very deep oil reservoirs, higher CO and H₂ concentrations may be tolerable. Removal of the H₂ when required can be undertaken with a PSA unit or a membrane unit. These units in turn may require H₂S to be removed to a sufficiently low content.

[0104] The resultant syngas can, being predominately a combination of CO₂ and CH₄ be piped to the oil reservoir, where it is used directly for miscible EOR. The preferred MMP is between around 20 and 50% higher than the required MMP for pure CO₂, but this is expected to be tolerable in many oil reservoirs. The required pressure is in the range of 150 to 250 bar, which is acceptable for EOR equipment.

[0105] Table 2, below, shows some potential gas mixtures (Case 1 to Case 6) derived from UCG syngas, depending upon operating conditions and surface facility configuration. Table 2 shows the corresponding MMP for these mixtures for light oil (60 g/mol) for temperatures of 38 °C and 74 °C. It is observed that with combinations of CO₂ and CH₄ with concentrations of CO+H₂ less than or equal to 14 mol%, that the MMP is in the range 110 to 220 bar (Cases 1, 2, 3, 4, and 6), which is expected to be acceptable for many potential miscible EOR floods.

[0106] When a significant amount of N₂ is present in the syngas, for example when air blown gasification is used as in Case 5 of Table 2, the MMP is observed to increase to above 300 bar. When such a high pressure is required for achieving miscibility, the syngas from air blown gasification is likely to be suitable only for immiscible oil displacement processes, or suitable in very deep light oil reservoirs where the reservoir pressure is already above 300 bar.
TABLE 2
Miscible EOR

<table>
<thead>
<tr>
<th>Syngas Comp.</th>
<th>Case 1</th>
<th>Case 2</th>
<th>Case 3</th>
<th>Case 4</th>
<th>Case 5</th>
<th>Case 6</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ mol%</td>
<td>1</td>
<td>1</td>
<td>0.5</td>
<td>0.6</td>
<td>0.3</td>
<td>0.6</td>
</tr>
<tr>
<td>CO mol%</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.07</td>
<td>0</td>
<td>0.14</td>
</tr>
<tr>
<td>H₂ mol%</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.07</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>N₂ mol%</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.01</td>
<td>0.4</td>
<td>0.01</td>
</tr>
<tr>
<td>CH₄ mol%</td>
<td>0</td>
<td>0</td>
<td>0.5</td>
<td>0.25</td>
<td>0.3</td>
<td>0.25</td>
</tr>
<tr>
<td>O₂ mol%</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>MMP bar</td>
<td>110</td>
<td>144</td>
<td>186</td>
<td>220</td>
<td>307</td>
<td>214</td>
</tr>
<tr>
<td>MMP psi</td>
<td>1,600</td>
<td>2,100</td>
<td>2,700</td>
<td>3,200</td>
<td>4,450</td>
<td>3,100</td>
</tr>
<tr>
<td>Oil g/mol</td>
<td>60</td>
<td>60</td>
<td>60</td>
<td>60</td>
<td>60</td>
<td>60</td>
</tr>
<tr>
<td>Temp °C</td>
<td>38</td>
<td>74</td>
<td>38</td>
<td>74</td>
<td>74</td>
<td>74</td>
</tr>
</tbody>
</table>

[0107] The injected CO₂- and CH₄-rich driver gas (e.g., in a supercritical fluid state) serves to enhance production of a hydrocarbon-containing fluid (including, for example, oil) from an oil well through a combination of mechanisms typically involving repressurisation of the underground reservoir and viscosity reduction of the trapped hydrocarbon (improving flow properties).

[0108] Typically, the CO₂- and CH₄-rich driver gas will be injected into the oil reservoir at a pressure in the range of about 150 (the MMP of CO₂) to 350 bar (the MMP of CH₄), and more preferably between about 150 and about 250 bar.

[0109] In one embodiment, the method further includes the step of introducing a methanation catalyst into the underground coal gasifier to promote in situ methanation of the driver gas.

[0110] Any suitable type and form of methanation catalyst can be used, and the catalyst can be introduced into the gasifier in any suitable way. For example, the methanation catalyst can be introduced into the gasifier pneumatically as a dust or
particulate, via an ignition, production or service well. The methanation catalyst can be introduced into one or more cavities or horizontal well passages of the gasifier. The methanation catalyst can be in the form of a fixed bed catalytic reactor or a well liner (including a part/portion of a well liner), or a catalyst associated with a well liner (including a part or portion thereof), introduced into an ignition, production and/or service well, and/or cavity or horizontal well passage of the gasifier.

The catalyst can be, for example, of the type that is not readily poisoned by sulphur. The catalyst can be, for example, a metal. Such metals can include, but are not limited to, Group IV(B), V(B), VI(B), or VIII metals, such as, for example, titanium, zirconium, hafnium, vanadium, niobium, tantalum, chromium, molybdenum, tungsten, iron, cobalt, nickel, ruthenium, rhodium, palladium, osmium, iridium, and platinum. Reduced iron, for example, is a metal which catalyses methanation in the presence of sulphur and also catalyses water-gas shift reactions.

The catalyst can be a mixture or combination of different metal types and/or metal compounds (e.g., different types of metal oxides). The catalyst can be, for example, a (reduced) metal which promotes methanation such that at least about 20% volume/volume of the product gas exiting the production well includes methane. Preferably, the catalyst is iron ore/iron oxide (Fe$_2$O$_3$ or Fe$_3$O$_4$), which is reduced in situ by H$_2$ and CO in the presence of steam resident within the gasifier.

Preferably, the catalyst is pneumatically conveyed as a particulate (dust) within a fluid stream, allowing the catalyst to remain airborne/suspended within the cavity, mixing with syngas resident within the cavity, and providing a large surface area for catalysing methanation of the syngas. The catalyst is preferably pneumatically conveyed at a rate so as to continuously promote methanation of the syngas.

In another embodiment, the method further includes the steps of injecting the CO$_2$- and CH$_4$-rich driver gas into a non-active cavity of the underground coal gasifier having a temperature of about 250 to about 450 °C, and recovering the driver gas for compression and injection into the oil reservoir. Suitably, the CO$_2$- and CH$_4$-
rich driver gas can be circulated through multiple non-active gasifier cavities in order to increase the concentration of CO$_2$ and CH$_4$ in the driver gas to the desired level.

[0115] As will be understood by those of ordinary skill in the art, passing a CO$_2$- and CH$_4$-rich driver gas through a hot, non-active cavity of an underground coal gasifier promotes further methanation of the driver gas according to the reactions:

\[
\begin{align*}
\text{CO} + 3\text{H}_2 & \leftrightarrow \text{CH}_4 + \text{H}_2\text{O} \\
\text{C} + 2\text{H}_2 & \rightarrow \text{CH}_4
\end{align*}
\]

[0116] In yet another embodiment, the method further includes the steps of shifting the CO content of the CO$_2$- and CH$_4$-rich driver gas to H$_2$ and removing the H$_2$ from the driver gas prior to injection into the oil reservoir. The H$_2$ can also be removed from the driver gas prior to injection into the oil reservoir without the added shifting step.

[0117] As discussed herein, methods and reactors for performing the water-gas shift reaction on a CO-containing syngas stream are well known to those of ordinary skill in the art.

[0118] When present, contaminant removal of a particular contaminant can be achieved as discussed herein. Similarly, separation and recovery of injected CO$_2$ and CH$_4$ from the recovered oil can be achieved as discussed herein, with recovered CH$_4$ being available to be injected into the oil reservoir for further EOR.

[0119] Typically, the CO$_2$ will be injected into the oil reservoir at a pressure in the range of about 110 to 140 bar.

[0120] When oil is produced, the injected CO$_2$ and CH$_4$ gases will be produced associated with the oil. Additional associated gases, which can include C$_1$ and C$_{2+}$ components, may also be produced from the reservoir depending upon the properties of the reservoir. At this point, it would be desirable to separate the hydrocarbon components from the oil, and from each other, as will be understood by those of ordinary skill in the art.
In yet another aspect, the invention provides a method for recovering a hydrocarbon-containing fluid from an oil reservoir, including the steps of (a) operating an underground coal gasifier to produce a syngas comprising $\text{H}_2$, $\text{CO}$, $\text{CH}_4$, and $\text{H}_2\text{O}$, (b) combusting the syngas with an oxidant to generate predominantly $\text{CO}_2$ and steam, (c) injecting the $\text{CO}_2$ and steam into the oil reservoir, and (d) recovering oil from the oil reservoir.

In one embodiment, the underground coal gasifier is operated at a pressure of greater than or equal to 80 bar. As discussed herein, operating an underground coal gasifier at a pressure of greater than or equal to 80 bar results in a produced syngas that is rich in $\text{CO}_2$ and $\text{CH}_4$ with minimal $\text{CO}$ and $\text{H}_2$.

As will be understood by those of ordinary skill in the art, when syngas is combusted with an oxidant (e.g., air, oxygen-enriched air, or a gas/gas mixture enriched with oxygen, or substantially pure oxygen) both $\text{CO}_2$ and steam are generated. For recovery of heavy oils or oil sands, a steam/$\text{CO}_2$ mixture is advantageous. Heavy oil and oil sands (also known as tar sands) contain a viscous form of petroleum known as bitumen, and require a combination of heat and solvents for economic recovery. Typically, heat is provided to the reservoir via the injection of steam.

Combustion of syngas with an oxidant can take place above ground, for example in a surface burner/furnace, or underground in the oil reservoir via a downhole generator.

As will be understood by those of ordinary skill in the art, a downhole generator is inserted into the oil reservoir via an injection well. Once introduced into the oil reservoir, the downhole generator is used to combust syngas with an oxidant and establish a predominantly steam/$\text{CO}_2$ mixture.

The injected or downhole generated steam/$\text{CO}_2$ mixture serves to enhance production of a hydrocarbon-containing fluid (including, for example, heavy oil) from an oil well through a combination of mechanisms including viscosity reduction of the trapped hydrocarbon (improving flow properties).
The downhole generator can be positionable and retractable, so that a steam/CO₂ mixture can be established in multiple locations within the oil reservoir. Positioning of the downhole generator can be achieved utilising either drilling pipe or coiled tubing connected to the generator and extendible within the injection well to position the downhole generator at a desired location within the oil reservoir.

In the figures, like reference numerals refer to like features.

Referring to the drawings, there is shown in Figure 1 a diagram of an integrated system and process for underground coal gasification and enhanced oil recovery.

Raw UCG syngas 10 produced by an underground coal gasifier 12 is passed through a water wash unit 15 for removal of entrained particulates, water soluble contaminants, and coal condensate 17, and an acid gas removal unit 20 for removal of carbon dioxide 22 and hydrogen sulphide 25, to provide clean syngas 27.

Clean syngas 27 is optionally fed into a water-gas shift reactor 30 and hydrogen separation unit 32, before being used as a feedstock in a synthesis unit 35 for the production of one or more desired products 36.

Any one or more of nitrogen 37 (from an air separation unit 40), carbon dioxide 22, a waste stream 42 from the synthesis unit 35, water 45 (e.g., from a water treatment unit 75), water/brine 70 (e.g., from a separation device 67), and steam 46 (e.g., from the water-gas shift reactor 30 or an optional power generation block 47) is injected into an underground oil reservoir 50 via an injection well 52.

The produced hydrocarbon-containing fluid 55 is passed to a separation unit 57 to separate gaseous components from liquid/solid components to generate a gaseous hydrocarbon product stream 60, a liquid hydrocarbon product stream 62 and, optionally, a stream 65 containing solids components from the hydrocarbon-containing fluid 55. The solids may also optionally be carried with the liquid hydrocarbon product stream 62 for later separation, or separated out prior to
separation unit 57, by well-known techniques such as settling, centrifugation and/or filtration.

[0134] In one embodiment, larger/denser solids are separated in conjunction with separation unit 57, and finer solids that may become entrained in liquid hydrocarbon product stream 62 are separated subsequently through well-known techniques such as filtration.

[0135] The liquid hydrocarbon product stream 62 will include a majority of the liquid components from the hydrocarbon-containing fluid 55 including, for example, oil and water/brine. The liquid hydrocarbon product stream 62 is subsequently processed via the separation device 67 to separate the water/brine 70 from the oil 72.

[0136] The gaseous hydrocarbon product stream 60 will include a majority of the gaseous components from the hydrocarbon-containing fluid 55, including gaseous hydrocarbons (and carbon dioxide to the extent present). The gaseous hydrocarbon product stream 60 can also include minor amounts of water vapour, as well as other contaminants if present, such as hydrogen sulphide.

[0137] Where the gaseous hydrocarbon product stream 60 contains more than trace amounts of acid gases, such as carbon dioxide and/or hydrogen sulphide, they can be removed via the acid gas removal unit 20. That is, all or a portion of the gaseous hydrocarbon product stream 60 exiting separation unit 57 can be combined with the syngas stream 10 or otherwise co-processed with syngas stream 10 in the acid gas removal unit 20.

[0138] Where the underground coal gasifier 12 is not located within the immediate vicinity of the oil reservoir 50, a separate acid gas removal unit 20 and associated gas treatment facilities may be constructed close to the oil reservoir 50.

[0139] Water/brine 70 from the separation device 67 is passed through the water treatment unit 75 for clean-up, to produce water 45. Optionally, water/brine 70 is
recirculated to the underground coal gasifier 12. Contaminated water 77 from the water wash unit 15 is also passed through the water treatment unit 75 for clean-up.

[0140] Water 45 from the water treatment unit 75 is optionally recirculated to the underground coal gasifier 12.

[0141] Carbon dioxide 22 from the acid gas removal unit 20 is recirculated to the underground coal gasifier 12 and/or the underground oil reservoir 50 via the injection well 52.

[0142] Oxidant 80 (oxygen) is provided by the air separation unit 40. In an alternate embodiment, oxidant 80 is air, provided by an air compressor (which is not shown).

[0143] Referring to Figure 2, a diagram of an integrated process for underground coal gasification and enhanced oil recovery is shown.

[0144] A CO₂- and CH₄-rich driver gas 90 with minimal CO and H₂ produced by an underground coal gasifier 12 operated at a pressure of greater than or equal to 80 bar is passed through a water wash unit 15 for removal of entrained particulates, water soluble contaminants, and coal condensate 17 and compressed to an appropriate pressure for injection into an underground oil reservoir 50 via an injection well 52. Optionally, the CO₂- and CH₄-rich driver gas 90 is passed through an acid gas removal unit 20 for selective removal of hydrogen sulphide 25 prior to compression to an appropriate pressure and injection into the underground oil reservoir 50 via the injection well 52.

[0145] The produced hydrocarbon-containing fluid 55 is passed to a separation unit 57 to separate gaseous components from liquid/solid components to generate a gaseous hydrocarbon product stream 60, a liquid hydrocarbon product stream 62 and, optionally, a stream 65 containing solids components from the hydrocarbon-containing fluid 55. The solids may also optionally be carried with the liquid hydrocarbon product stream 62 for later separation, or separated out prior to
separation unit 57, by well-known techniques such as settling, centrifugation and/or filtration.

[0146] In one embodiment, larger/denser solids are separated in conjunction with separation unit 57, and finer solids that may become entrained in liquid hydrocarbon product stream 62 are separated subsequently through well-known techniques such as filtration.

[0147] The liquid hydrocarbon product stream 62 will include a majority of the liquid components from the hydrocarbon-containing fluid 55 including, for example, oil and water/brine. The liquid hydrocarbon product stream 62 is subsequently processed via a separation device 67 to separate the water/brine 70 from the oil 72.

[0148] The gaseous hydrocarbon product stream 60 will include a majority of the gaseous components from the hydrocarbon-containing fluid 55, including gaseous hydrocarbons (and carbon dioxide to the extent present). The gaseous hydrocarbon product stream 60 can also include minor amounts of water vapour, as well as other contaminants if present, such as hydrogen sulphide.

[0149] Where the gaseous hydrocarbon product stream 60 contains more than trace amounts of acid gases, such as CO₂ and/or H₂S, they can be removed via the acid gas removal unit 20.

[0150] Where the underground coal gasifier 12 is not located within the immediate vicinity of the oil reservoir 50, a separate acid gas removal unit 20 and associated gas treatment facilities may be constructed close to the oil reservoir 50.

[0151] Water/brine 70 from the separation device 67 is passed through a water treatment unit 75 for clean-up, to produce water 45. Optionally, water/brine 70 is recirculated to the underground coal gasifier 12 and/or the underground oil reservoir 50 via the injection well 52. Contaminated water 77 from the water wash unit 15 is also passed through the water treatment unit 75 for clean-up.
[0152] Water 45 from the water treatment unit 75 is optionally recirculated to the underground coal gasifier 12.

[0153] Carbon dioxide 22 from the acid gas removal unit 20 is recirculated to the underground coal gasifier 12 and/or the underground oil reservoir 50 via the injection well 52.

[0154] Oxidant 80 (oxygen) is provided by an air separation unit 40. In an alternate embodiment, oxidant 80 is air, provided by an air compressor (which is not shown).

[0155] Referring to Figure 3, a diagram of an additional integrated process for underground coal gasification and enhanced oil recovery is shown.

[0156] Raw UCG syngas 10 produced by an underground coal gasifier 12 is passed through a water wash unit 15 for removal of entrained particulates, water soluble contaminants, and coal condensate 17 and injected into an underground oil reservoir 50 via an injection well 52 where it is combusted with an oxidant 80 (oxygen), provided by an air separation unit 40, in a downhole generator 95 to generate a steam/CO$_2$ mixture. Optionally, the syngas 10 is passed through an acid gas removal unit 20 for selective removal of hydrogen sulphide 25 prior to injection into the underground oil reservoir 50 via the injection well 52. In an alternate embodiment, combustion of the syngas 10 with the oxidant 80 (oxygen) occurs in a surface furnace (which is not shown).

[0157] Optionally, water 45 is provided to the downhole generator 95 to increase the amount of steam in the steam/CO$_2$ mixture.

[0158] In an alternate embodiment, the oxidant 80 is air, provided by an air compressor (which is not shown).

[0159] The produced hydrocarbon-containing fluid 55 is passed to a separation unit 57 to separate gaseous components from liquid/solid components to generate a gaseous hydrocarbon product stream 60, a liquid hydrocarbon product stream 62
and, optionally, a stream 65 containing solids components from the hydrocarbon-containing fluid 55. The solids may also optionally be carried with the liquid hydrocarbon product stream 62 for later separation, or separated out prior to separation unit 57, by well-known techniques such as settling, centrifugation and/or filtration.

[0160] In one embodiment, larger/denser solids are separated in conjunction with separation unit 57, and finer solids that may become entrained in liquid hydrocarbon product stream 62 are separated subsequently through well-known techniques such as filtration.

[0161] The liquid hydrocarbon product stream 62 will include a majority of the liquid components from the hydrocarbon-containing fluid 55 including, for example, oil and water/brine. The liquid hydrocarbon product stream 62 is subsequently processed via a separation device 67 to separate the water/brine 70 from the oil 72.

[0162] The gaseous hydrocarbon product stream 60 will include a majority of the gaseous components from the hydrocarbon-containing fluid 55, including gaseous hydrocarbons and CO₂. The gaseous hydrocarbon product stream 60 can also include minor amounts of water vapour, as well as other contaminants if present, such as hydrogen sulphide.

[0163] Acid gases, such as CO₂ and/or H₂S, can be removed via the acid gas removal unit 20.

[0164] Where the underground coal gasifier 12 is not located within the immediate vicinity of the oil reservoir 50, a separate acid gas removal unit 20 and associated gas treatment facilities may be constructed close to the oil reservoir 50.

[0165] Water/brine 70 from the separation device 67 is passed through a water treatment unit 75 for clean-up, to produce water 45. Optionally, water/brine 70 is recirculated to the underground coal gasifier 12. Contaminated water 77 from the water wash unit 15 is also passed through the water treatment unit 75 for clean-up.
[0166] Water 45 from the water treatment unit 75 is optionally recirculated to the underground coal gasifier 12.

[0167] Carbon dioxide 22 from the acid gas removal unit 20 is recirculated to the underground coal gasifier 12 and/or the underground oil reservoir 50 via the injection well 52.

[0168] Those of ordinary skill in the art will appreciate that there may be elements and/or units for adjusting the pressure, flow, temperature, and composition of required streams, and for linking various aspects of an integrated UCG and EOR system/process, for which details have been omitted. There may be units for heating or cooling, and supporting plants to provide the utilities required for the facilities described herein. Moreover, there are different technologies available to accomplish the function of the units and facilities described, which selection will depend, inter alia, on the specific requirements and properties of the underground coal seam, oil reservoir, and associated geology of the UCG and EOR processes.

[0169] Reference throughout this specification to “one embodiment” or “an embodiment” means that a particular feature, structure, or characteristic described in connection with the embodiment is included in at least one embodiment of the present invention. Thus, the appearance of the phrases “in one embodiment” or “in an embodiment” in various places throughout this specification are not necessarily all referring to the same embodiment. Furthermore, the particular features, structures, or characteristics can be combined in any suitable manner in one or more combinations.

[0170] Throughout the specification the aim has been to describe the preferred embodiments of the invention without limiting the invention to any one embodiment or specific collection of features. It will therefore be appreciated by those of skill in the art that, in light of the instant disclosure, various modifications and changes can be made in the particular embodiments exemplified without departing from the scope of the present invention.
CLAIMS

1. An integrated system for providing gas and liquid for injection in an oil reservoir for recovery of a hydrocarbon-containing fluid and production of higher hydrocarbons from underground coal, comprising:
   a. an air separation unit for production of oxygen and nitrogen;
   b. an underground coal gasifier adapted to produce an in situ syngas comprising H\textsubscript{2}, CO, CH\textsubscript{4}, CO\textsubscript{2}, and H\textsubscript{2}O;
   c. a syngas clean-up facility adapted to remove and recover contaminants and CO\textsubscript{2} from the syngas;
   d. a syngas conditioning unit adapted to adjust the ratio of H\textsubscript{2} to CO in the syngas;
   e. a synthesis unit adapted to synthesise a product from the syngas; and
   f. an injection well in fluid communication with the oil reservoir, the injection well adapted to inject one or more of the following into the oil reservoir:
      (i) nitrogen from the air separation unit;
      (ii) CO\textsubscript{2} from the syngas clean-up facility;
      (iii) a waste stream from the synthesis unit;
      (iv) water; and
      (v) steam.

2. An integrated system for providing gas and liquid for injection in an oil reservoir for recovery of a hydrocarbon-containing fluid and production of higher hydrocarbons from underground coal, comprising:
   a. an air compression unit;
   b. an underground coal gasifier adapted to produce an in situ syngas comprising H\textsubscript{2}, CO, CH\textsubscript{4}, CO\textsubscript{2}, and H\textsubscript{2}O;
   c. a syngas clean-up facility adapted to remove and recover contaminants and CO\textsubscript{2} from the syngas;
   d. a syngas conditioning unit adapted to adjust the ratio of H\textsubscript{2} to CO in the syngas;
   e. a synthesis unit adapted to synthesise a product from the syngas; and
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f. an injection well in fluid communication with the oil reservoir, the injection well adapted to inject one or more of the following into the oil reservoir:
   (i) CO₂ from the syngas clean-up facility;
   (ii) a waste stream from the synthesis unit;
   (iii) water; and
   (iv) steam.

3. The integrated system of claim 1 or claim 2, wherein the synthesis unit adapted to synthesise a product from the syngas is adapted to synthesise ammonia, methanol, and/or oxo alcohols.

4. The integrated system of claim 1 or claim 2, wherein the synthesis unit adapted to synthesise a product from the syngas is a Fischer-Tropsch synthesis unit adapted to synthesise higher hydrocarbons from the syngas.

5. A method for providing gas and liquid for injection in an oil reservoir for recovery of a hydrocarbon-containing fluid and production of higher hydrocarbons from underground coal, comprising the steps of:
   a. separating air into an oxygen-rich fraction and a nitrogen-rich fraction;
   b. recombining a portion of the oxygen-rich fraction with a portion of the nitrogen-rich fraction to produce an oxidant having a desired oxygen concentration;
   c. injecting the oxidant into an underground coal gasifier to produce an in situ syngas comprising H₂, CO, CH₄, CO₂, and H₂O;
   d. removing contaminants and CO₂ from the syngas;
   e. recovering the CO₂;
   f. synthesising a product from the syngas;
   g. injecting one or more of:
      (i) nitrogen from the nitrogen-rich fraction;
      (ii) the recovered CO₂;
      (iii) a waste stream from the synthesis of the product;
      (iv) water; and
      (v) steam
    into an injection well in fluid communication with the oil reservoir; and
h. recovering oil from the oil reservoir.

6. A method for providing gas and liquid for injection in an oil reservoir for recovery of a hydrocarbon-containing fluid and production of higher hydrocarbons from underground coal, comprising the steps of:
   a. compressing air for use as an oxidant;
   b. injecting the oxidant into an underground coal gasifier to produce an in situ syngas comprising $\text{H}_2$, CO, CH$_4$, CO$_2$, and H$_2$O;
   c. removing contaminants and CO$_2$ from the syngas;
   d. recovering the CO$_2$;
   e. synthesising a product from the syngas;
   f. injecting one or more of:
      (i) the recovered CO$_2$;
      (ii) a waste stream from the synthesis of the product;
      (iii) water; and
      (iv) steam
   into an injection well in fluid communication with the oil reservoir; and
   g. recovering oil from the oil reservoir.

7. The method of claim 5 or claim 6, wherein water, steam and/or CO$_2$ are injected into the underground coal gasifier along with the oxidant.

8. The method of any one of claims 5 to 7, further comprising the step of conditioning the syngas to adjust the ratio of H$_2$ to CO in the syngas.

9. The method of any one of claims 5 to 8, further comprising the step of separating the injected CO$_2$ from the recovered oil.

10. The method of claim 9, further comprising the step of injecting the separated CO$_2$ into the oil reservoir.

11. A method for recovering a hydrocarbon-containing fluid from an oil reservoir, comprising the steps of:
a. operating an underground coal gasifier at a pressure of greater than or equal to 80 bar to produce a CO₂- and CH₄-rich driver gas with minimal CO and H₂;
b. compressing the driver gas to an appropriate pressure for injection into the oil reservoir;
c. injecting the driver gas into the oil reservoir; and
d. recovering oil from the oil reservoir.

12. The method of claim 11, further comprising the step of introducing a methanation catalyst into the underground coal gasifier to promote methanation of the driver gas within the gasifier.

13. The method of claim 11 or claim 12, further comprising the steps of shifting the CO content of the CO₂- and CH₄-rich driver gas to H₂ and removing the H₂ from the driver gas prior to injection into the oil reservoir.

14. The method of claim 11 or claim 12, further comprising the step of removing the H₂ from the CO₂- and CH₄-rich driver gas prior to injection into the oil reservoir.

15. The method of claim 13 or claim 14, further comprising the step of removing contaminants from the CO₂- and CH₄-rich driver gas.

16. The method of any one of claims 11 to 15, further comprising the step of removing higher hydrocarbons from the CO₂- and CH₄-rich driver gas.

17. The method of any one of claims 11 to 16, wherein the CO₂- and CH₄-rich driver gas is compressed to a pressure appropriate for miscible displacement of oil from the oil reservoir.

18. The method of claim 17, wherein the CO₂- and CH₄-rich driver gas is compressed to a pressure in the range of 150 to 250 bar.

19. The method of any one of claims 11 to 18, further comprising the step of separating the injected CO₂ and CH₄ from the recovered oil.
20. The method of claim 19, further comprising the step of separating the \( \text{CO}_2 \) from the \( \text{CH}_4 \).

21. The method of claim 20, further comprising the steps of compressing the separated \( \text{CO}_2 \) to an appropriate pressure for injection into the oil reservoir and injecting the \( \text{CO}_2 \) into the oil reservoir.

22. The method of claim 21, wherein the separated \( \text{CO}_2 \) is compressed to a pressure appropriate for miscible displacement of oil from the oil reservoir.

23. The method of claim 22, wherein the separated \( \text{CO}_2 \) is compressed to a pressure in the range of 110 to 140 bar.

24. The method of any one of claims 11 to 23, further comprising the steps of injecting the \( \text{CO}_2 \)- and \( \text{CH}_4 \)-rich driver gas into a non-active cavity of the underground coal gasifier having a temperature of about 250 to about 450 °C, and recovering the driver gas for compression and injection into the oil reservoir.

25. A method for recovering a hydrocarbon-containing fluid from an oil reservoir, comprising the steps of:
   a. operating an underground coal gasifier to produce a syngas comprising \( \text{H}_2 \), \( \text{CO} \), \( \text{CH}_4 \), and \( \text{H}_2\text{O} \);
   b. combusting the syngas with an oxidant to generate predominantly \( \text{CO}_2 \) and steam;
   c. injecting the \( \text{CO}_2 \) and steam into the oil reservoir; and
   d. recovering oil from the oil reservoir.

26. The method of claim 25, wherein the underground coal gasifier is operated at a pressure of greater than or equal to 80 bar.

27. The method of claim 25 or claim 26, wherein the syngas is combusted with the oxidant in a surface furnace.
28. The method of claim 25 or claim 26, wherein the syngas is combusted with the oxidant in a downhole generator.

29. The method of any one of claims 25 to 28, wherein the oil is a heavy oil.

30. The method of any one of claims 25 to 29, wherein the oil reservoir comprises oil sands.