



- (51) **International Patent Classification:**
E21B 43/16 (2006.01)
- (21) **International Application Number:**
PCT/US2013/039869
- (22) **International Filing Date:**
7 May 2013 (07.05.2013)
- (25) **Filing Language:** English
- (26) **Publication Language:** English
- (30) **Priority Data:**
61/652,668 29 May 2012 (29.05.2012) US
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- (81) **Designated States (unless otherwise indicated, for every kind of national protection available):** AE, AG, AL, AM,

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

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

Declarations under Rule 4.17:

- as to applicant's entitlement to apply for and be granted a patent (Rule 4.17(ii))
- as to the applicant's entitlement to claim the priority of the earlier application (Rule 4.17(iii))

Published:

- with international search report (Art. 21(3))
- before the expiration of the time limit for amending the claims and to be republished in the event of receipt of amendments (Rule 48.2(h))

(54) **Title:** SYSTEMS AND METHODS FOR HYDROTREATING A SHALE OIL STREAM USING HYDROGEN GAS THAT IS CONCENTRATED FROM THE SHALE OIL STREAM

(57) **Abstract:** Systems and methods for hydrotreating a liquid fraction of a shale oil stream using hydrogen gas that is concentrated from a gaseous fraction of the shale oil stream. The systems and methods include providing a portion of the gaseous fraction to a sorptive separation assembly and separating a concentrated hydrogen stream from the portion of the gaseous fraction within the sorptive separation assembly. The system and methods further include providing the concentrated hydrogen stream and the liquid fraction to a hydrotreater and reacting the concentrated hydrogen stream with the liquid fraction within the hydrotreater to produce the hydrotreated liquid stream. The systems and methods may include generating the shale oil stream within a subterranean formation using an in situ process, such as an in situ shale oil conversion process and/or providing a supplemental hydrogen stream to the hydrotreater.



**SYSTEMS AND METHODS FOR HYDROTREATING A SHALE OIL STREAM
USING HYDROGEN GAS THAT IS CONCENTRATED FROM THE SHALE OIL
STREAM**

5 Cross-Reference To Related Application

[0001] This application claims the priority benefit of U.S. Provisional Patent Application 61/652,668 filed 29 May 2012 entitled Systems and Methods For Hydrotreating A Shale Oil Stream Using Hydrogen Gas That Is Concentrated From The Shale Oil Stream, the entirety of which is incorporated by reference herein.

Field of the Disclosure

[0002] The present disclosure is directed generally to systems and methods for the processing of a shale oil stream that is produced from a subterranean formation, and more particularly to systems and methods that include the use of hydrogen gas that is present within a gaseous fraction of the shale oil stream to hydrotreat a liquid fraction of the shale oil stream.

Background of the Disclosure

[0003] Oil shale is a sedimentary rock that contains a significant fraction of solid, or quasi-solid, organic compounds, which may be referred to herein as kerogen. A number of processes have been developed to convert this kerogen to a liquid form, which may be referred to herein as shale oil. Worldwide shale oil reserves are estimated to be significantly larger than conventional crude oil reserves and represent an alternative natural resource that may be utilized to meet global hydrocarbon demands. However, shale oil is an unconventional hydrocarbon resource that may require additional treatment prior to being transferred in existing, or conventional, crude oil pipelines and/or processed in existing, or conventional, crude oil processing plants.

[0004] This additional treatment may include upgrading the shale oil to meet refinery feedstock and/or pipeline specifications. As illustrative, non-exclusive examples, shale oil may be produced from oil shale by heating the oil shale in an *in situ* retort process to artificially mature the kerogen and produce a shale oil stream, which may include both a liquid fraction and a gaseous fraction, therefrom. However, the liquid fraction of the shale oil

stream may include an undesirably high concentration of unsaturated carbon bonds, or olefinic materials. These olefinic materials may react, polymerize, and/or otherwise agglomerate, causing blockage and/or gumming within hydrocarbon processing and/or transportation equipment; and their concentration within the shale oil stream may be reduced
5 to meet refinery feedstock and/or pipeline specifications.

[0005] Hydrotreating, which includes reacting the liquid fraction of the shale oil stream with hydrogen gas, may be utilized to produce a hydrotreated liquid stream that includes a lower concentration of olefinic materials than the concentration of olefinic materials within the liquid fraction. However, hydrotreating requires a source of hydrogen gas.

10 [0006] Traditionally, this hydrogen gas has been produced by utilizing a reforming reaction to react a hydrocarbon with water and produce the hydrogen gas for the hydrotreating reaction therefrom. However, typical reforming reactions require relatively large quantities of water, with a 3:4, or larger, volumetric ratio of water utilized to produce hydrogen gas to the hydrotreated liquid stream that is produced by the hydrotreating process
15 being common.

[0007] Shale oil reserves often are located in areas that have limited water availability and/or where the consumption of large quantities of water to produce hydrogen gas may present environmental concerns. Thus, there exists a need for hydrotreating processes that may be utilized to decrease the concentration of olefinic materials within the liquid fraction
20 of the shale oil stream while utilizing less water than traditional hydrotreating techniques.

Summary of the Disclosure

[0008] Systems and methods for hydrotreating a liquid fraction of a shale oil stream using hydrogen gas that is concentrated from a gaseous fraction of the shale oil stream. The systems and methods include providing a portion of the gaseous fraction to a sorptive
25 separation assembly and separating a concentrated hydrogen stream from the portion of the gaseous fraction within the sorptive separation assembly. The system and methods further include providing the concentrated hydrogen stream and the liquid fraction to a hydrotreater and reacting the concentrated hydrogen stream with the liquid fraction within the hydrotreater to produce the hydrotreated liquid stream.

30 [0009] In some embodiments, the systems and methods may include generating the shale oil stream within a subterranean formation using an *in situ* process, such as an *in situ* shale oil conversion process, and/or separating the liquid fraction of the shale oil stream from the

gaseous fraction of the shale oil stream. In some embodiments, the systems and methods may include transferring the shale oil stream from the subterranean formation to a hydrotreating assembly that includes the sorptive separation assembly and/or the hydrotreater. In some embodiments, the transferring may include transferring without prior
5 treatment of the shale oil stream to decrease a concentration of olefinic materials therein.

[0010] In some embodiments, the systems and methods may include providing a supplemental hydrogen stream to the hydrotreater. In some embodiments, the supplemental hydrogen stream may be produced by a reforming apparatus. In some embodiments, the reforming apparatus may produce the supplemental hydrogen stream from a gaseous
10 hydrocarbon stream that is separated from the gaseous fraction of the shale oil stream.

Brief Description of the Drawings

[0011] Fig. 1 is a schematic representation of an illustrative, non-exclusive example of hydrotreating systems according to the present disclosure.

[0012] Fig. 2 is a flowchart depicting methods according to the present disclosure of
15 hydrotreating a liquid fraction of a shale oil stream using hydrogen gas that is obtained from a gaseous fraction of the shale oil stream.

Detailed Description and Best Mode of the Disclosure

[0013] Fig. 1 is a schematic representation of an illustrative, non-exclusive example of hydrotreating systems 30 according to the present disclosure. A hydrotreating system 30 may
20 be located proximal to, form a portion of, and/or be associated with a shale oil production site 10 associated with a shale oil source. The hydrotreating system 30 may be configured to receive a shale oil stream 20 that includes a liquid fraction 22 and a gaseous fraction 24, such as from the shale oil source 12. Hydrotreating system 30 may include and/or be in fluid communication with a liquid-gas separator 40 that is configured to separate liquid fraction 22
25 from gaseous fraction 24. When present, liquid-gas separator 40 also may be referred to herein as a liquid-gas separation assembly 40 and/or vapor-liquid separator 40.

[0014] Gaseous fraction 24, which may include hydrogen gas 46 and other gasses, such as gaseous hydrocarbons 55, contaminants 48, and/or impurities 68, may be provided to a contaminant removal assembly 50. The contaminant removal assembly may be configured to
30 remove one or more contaminants 48 from gaseous fraction 24 of the shale oil stream and to produce a purified gaseous fraction 54 therefrom. A portion of gaseous fraction 24, such as

purified gaseous fraction 54, then may be provided to a sorptive separation assembly 70, which may produce a concentrated hydrogen stream 74 containing hydrogen gas 46 therefrom. Concentrated hydrogen stream 74, and liquid fraction 22 of the shale oil stream, may be provided to a hydrotreater 90, which may react the concentrated hydrogen stream with liquid fraction 22 and produce hydrotreated liquid stream 92 therefrom.

[0015] As shown in dashed lines in Fig. 1, sorptive separation assembly 70 may, in addition to producing concentrated hydrogen stream 74, optionally produce impurities stream 72, which includes impurities 68. Similarly, and as also shown in dashed lines in Fig. 1, contaminant removal assembly 50 may, in addition to purified gaseous fraction 54, optionally produce contaminant stream 52 and/or gaseous hydrocarbon stream 56, which may include contaminants 48 and/or gaseous hydrocarbons 55, respectively, from gaseous fraction 24. The gaseous hydrocarbon stream, which may include methane, ethane, propane, and/or gaseous hydrocarbons with more than three carbon atoms, optionally may be provided to a reforming apparatus 60 that may be configured to react gaseous hydrocarbon stream 56 with a supplemental reactant stream 61 and to produce a reformat stream 62 therefrom.

[0016] As shown in dashed lines in Fig. 1, reformat stream 62 may provide additional hydrogen gas 46 directly to hydrotreater 90. Additionally or alternatively, a concentration of hydrogen gas in reformat stream 62 may be increased prior to providing a portion of the reformat stream to the hydrotreater. As an illustrative, non-exclusive example, and as shown in dash-dot lines in Fig. 1, the reformat stream may be provided with gaseous fraction 24 and/or purified gaseous fraction 54 to sorptive separation assembly 70. As another illustrative, non-exclusive example, and as shown in dash-dot-dot lines in Fig. 1, the reformat stream may be combined with concentrated hydrogen stream 74 prior to being provided to the hydrotreater. As yet another illustrative, non-exclusive example, reforming apparatus 60 may include and/or be in fluid communication with a purification assembly 63, which also may be referred to herein as a separation assembly 63, that is configured to increase a concentration of hydrogen gas in the reformat stream.

[0017] Shale oil source 12 may include and/or be any suitable subterranean formation 13 that includes an organic-rich rock that may be stimulated to produce and/or generate shale oil stream 20. As an illustrative, non-exclusive example, subterranean formation 13 may include and/or be an oil shale formation 15 that includes kerogen. When subterranean formation 13 includes oil shale formation 15, an *in situ* conversion process may be utilized to convert, or decompose, the kerogen that is present within the oil shale formation into shale oil, which

may then be pumped and/or conveyed as shale oil stream 20 through a hydrocarbon well 14 from the subterranean formation and to hydrotreating system 30. When the kerogen is converted to shale oil stream 20 using the *in situ* conversion process, subterranean formation 13 also may be referred to herein as including and/or being a chemical reactor, a subterranean chemical reactor, and/or an *in situ* chemical reactor.

[0018] Illustrative, non-exclusive examples of *in situ* conversion processes according to the present disclosure include any suitable pyrolysis reaction, shale oil retort process, shale oil heat treating process, hydrogenation reaction, thermal dissolution process, and/or shale oil conversion process that may be utilized and/or performed within subterranean formation 13. As an illustrative, non-exclusive example, an *in situ* pyrolysis reaction may be performed by increasing the temperature of the kerogen that is present within oil shale formation 15 to a suitable *in situ* pyrolysis temperature. This heating decomposes, or artificially ages, the kerogen and converts the kerogen into shale oil that includes liquid fraction 22 and gaseous fraction 24. Illustrative, non-exclusive examples of *in situ* pyrolysis temperatures according to the present disclosure include temperatures of at least 200 °C, at least 225 °C, at least 250 °C, at least 275 °C, at least 300 °C, at least 325 °C, at least 350 °C, at least 375 °C, at least 400 °C, and/or *in situ* pyrolysis temperatures of less than 600 °C, less than 550 °C, less than 500 °C, less than 450 °C, less than 400 °C, or less than 350 °C.

[0019] As discussed in more detail herein, hydrotreating system 30 may be proximal to, form a portion of, and/or be associated with shale oil production site 10. As such, a distance, or separation distance, between hydrotreating assembly 30 and/or a portion thereof and hydrocarbon well 14 and/or a wellhead 16 that may be associated therewith may be less than a threshold distance. Illustrative, non-exclusive examples of threshold distances according to the present disclosure include threshold distances of less than 10 kilometers (km), less than 8 km, less than 6 km, less than 5 km, less than 4 km, less than 3 km, less than 2 km, less than 1 km, less than 0.5 km, less than 0.25 km, or less than 0.1 km. Accordingly, it is within the scope of the present disclosure that the hydrotreating system 30 may be located at or near the shale oil production site from which shale oil stream 20 is produced or otherwise obtained, as opposed to conventional systems in which the hydrotreating system often is located much farther away from the shale oil production site.

[0020] Shale oil stream 20 may include any suitable fluid that may be produced by shale oil source 12 and/or provided to hydrotreating system 30. As illustrative, non-exclusive examples, the shale oil stream may include a reservoir fluid, kerogen, aged kerogen, liquid

hydrocarbons, and/or gaseous hydrocarbons that may form a portion of liquid fraction 22 and/or gaseous fraction 24 of the shale oil stream. As discussed in more detail herein, shale oil stream 20 and/or liquid fraction 22 thereof may include a plurality of hydrocarbon molecules, a portion of which may include unsaturated carbon bonds and may be referred to
5 herein as olefinic materials.

[0021] It is within the scope of the present disclosure that hydrotreating system 30 may be configured to receive a shale oil stream 20 that has not been treated, reacted, and/or hydrotreated to decrease a concentration of unsaturated carbon bonds therein prior to being provided to the hydrotreating system. As illustrative, non-exclusive examples, shale oil
10 stream 20 may be provided to hydrotreating system 30 directly from subterranean formation 13 and without prior *in situ* treatment within subterranean formation 13 and/or prior *ex situ* treatment outside of the subterranean formation to decrease the concentration of unsaturated carbon bonds, or olefinic materials, therein.

[0022] Liquid fraction 22 of shale oil stream 20 may include any suitable liquid and/or
15 condensable liquid that may be produced by subterranean formation 13 and/or provided to hydrotreating system 30. As illustrative, non-exclusive examples, liquid fraction 22 may include the reservoir fluid, liquid hydrocarbons, a light oil, unsaturated hydrocarbon molecules, one or more olefins (or olefinic materials), one or more alkenes, and/or one or more alkynes. It is within the scope of the present disclosure that the unsaturated
20 hydrocarbon molecules may comprise any suitable portion of liquid fraction 22. As illustrative, non-exclusive examples, a mole fraction of unsaturated hydrocarbon molecules within liquid fraction 22 may be less than 20%, less than 15%, less than 12.5%, less than 10%, less than 7.5%, or less than 5%. Additionally or alternatively, the mole fraction of unsaturated hydrocarbon molecules within liquid fraction 22 may be greater than 1%, greater
25 than 2.5%, greater than 5%, greater than 7.5%, greater than 10%, greater than 12.5%, or greater than 15%.

[0023] Similarly, gaseous fraction 24 of shale oil stream 20 may include any gas and/or
gasses that may be produced by subterranean formation 13 and/or provided to hydrotreating system 30. As illustrative, non-exclusive examples, gaseous fraction 24 may include
30 hydrogen gas 46, contaminants 48, gaseous hydrocarbons 55, and/or impurities 68. Illustrative, non-exclusive examples of materials that may be present in gaseous fractions 24 according to the present disclosure include water, hydrogen sulfide, carbon dioxide, carbon monoxide, sulfur, arsenic, arsine, reservoir fluid, hydrocarbons, gaseous hydrocarbons,

volatile hydrocarbons, methane, ethane, propane, and/or hydrocarbons with more than three carbon atoms.

[0024] In general, contaminants 48 may include any material and/or materials that may be detrimental to the operation, or the efficient operation, of sorptive separation assembly 70.

5 As such, gas pre-cleaning assembly 50 may be configured to remove the contaminants from gaseous fraction 24 prior to supply of the remainder of the gaseous fraction to the sorptive separation assembly in order to improve the operation of the sorptive separation assembly. Illustrative, non-exclusive examples of such contaminants include sulfur and/or arsenic-containing compounds.

10 [0025] In contrast, impurities 68 may include any material and/or materials that may be present in supply stream 71 that is supplied to sorptive separation assembly 70 and that may serve to decrease the concentration, or partial pressure, of hydrogen gas within the supply stream. Illustrative, non-exclusive examples of such impurities include water and/or carbon dioxide. It is within the scope of the present disclosure that, while not utilized within
15 hydrotreating system 30, contaminants 48 and/or impurities 68 may include one or more useful and/or valuable materials that may be utilized in another process (apart from the separation and/or hydrotreating processes) and/or stored for later use.

[0026] Gaseous hydrocarbons 55 may include any suitable carbon-containing compound that may be present within gaseous fraction 24 and may be in a gaseous and/or vaporous state
20 at the temperature and pressure of the gaseous fraction. Illustrative, non-exclusive examples of gaseous hydrocarbons 55 according to the present disclosure include methane, ethane, propane, and/or gaseous hydrocarbons with more than three carbon atoms.

[0027] Gaseous fraction 24 may include any suitable concentration of hydrogen gas. As illustrative, non-exclusive examples, the gaseous fraction may include at least 3 mole%, at
25 least 4 mole%, at least 5 mole%, at least 6 mole%, at least 8 mole%, at least 10 mole%, at least 12 mole%, at least 15 mole%, less than 30 mole%, less than 28 mole%, less than 25 mole%, less than 22 mole%, less than 20 mole%, less than 18 mole%, less than 16 mole%, and/or less than 15 mole% hydrogen gas.

[0028] Liquid-gas separator 40 may include and/or be any suitable structure that is
30 configured to receive shale oil stream 20 and to separate the shale oil stream into liquid fraction 22 and gaseous fraction 24. Illustrative, non-exclusive examples of liquid-gas separators that may be utilized with the systems and methods according to the present

disclosure include oil-gas separators, stage separators, traps, knockout vessels, flash chambers, expansion separators, scrubbers, and/or filters.

[0029] Contaminant removal assembly 50 may include and/or be any suitable structure that is configured to decrease a concentration of one or more contaminants 48 in gaseous fraction 24 and to produce purified gaseous fraction 54, and optionally contaminant stream 52 and/or gaseous hydrocarbon stream 56, therefrom. Illustrative, non-exclusive examples of contaminant removal assemblies that may be utilized with the system and methods according to the present disclosure include any suitable scrubber, membrane separation assembly, sorptive separation assembly, pressure-driven separation assembly, temperature-driven separation assembly, condenser, reactive separation assembly, and/or gettering assembly.

[0030] Reforming apparatus 60 may include and/or be any suitable structure that is configured to receive gaseous hydrocarbon stream 56, and optionally supplemental reactant stream 61, and to produce reformat stream 62 therefrom. Supplemental reactant stream 61 may include any suitable material that may react with gaseous hydrocarbon stream 56 within reforming apparatus 60 to produce reformat stream 62. Illustrative, non-exclusive examples of materials that may comprise the supplemental reactant stream include water, steam, oxygen, air, and/or carbon dioxide.

[0031] As discussed in more detail herein, it is within the scope of the present disclosure that reforming apparatus 60 may include and/or be in fluid communication with purification assembly 63. Purification assembly 63 may include any suitable structure that is configured to increase the concentration of hydrogen gas and/or decrease the concentration of one or more contaminants 48 and/or impurities 68 within the reformat stream. As an illustrative, non-exclusive example, purification assembly 63 may include a water-gas shift reactor that is configured to reduce a concentration of carbon monoxide and/or increase the concentration of hydrogen gas within the reformat stream. As another illustrative, non-exclusive example, purification assembly 63 may include any suitable separation assembly 63, illustrative, non-exclusive examples of which are discussed in more detail herein with reference to contaminant removal assembly 50 and/or sorptive separation assembly 70.

[0032] It is within the scope of the present disclosure that a flow rate of hydrogen gas 46 that is present within concentrated hydrogen stream 74 may be sufficient to hydrotreat all, or at least substantially all and/or at least a desired amount, of liquid fraction 22. Under these conditions, reforming apparatus 60 optionally may not be utilized to produce reformat

stream 62, may be used to produce the reformat stream intermittently, and/or may not be present within hydrotreating system 30.

[0033] However, it is also within the scope of the present disclosure that the flow rate of hydrogen gas 46 that is present within concentrated hydrogen stream 74 may not be sufficient to hydrotreat all, or at least substantially all and/or at least a desired amount, of liquid fraction 22. Under these conditions, reforming apparatus 60 may be utilized to produce reformat stream 62, which may provide an additional, or supplemental, source of hydrogen gas to hydrotreater 90 and/or supplement concentrated hydrogen stream 74. It is within the scope of the present disclosure that concentrated hydrogen stream 74 may be sufficient to hydrotreat at least 40%, at least 50%, at least 60%, at least 70%, at least 80%, at least 90%, at least 95%, at least 99%, or substantially all of liquid fraction 22. When reforming apparatus 60 is utilized to produce reformat stream 62, it is within the scope of the present disclosure that a flow rate of reformat stream 62 optionally may be controlled or otherwise regulated to provide a flow rate of the reformat stream that, when combined with concentrated hydrogen stream 74, is sufficient to provide for complete, or at least substantially complete, reaction of liquid fraction 22 within hydrotreater 90.

[0034] Utilizing concentrated hydrogen stream 74 to provide at least a substantial portion of the hydrogen gas that may be required, or consumed, by hydrotreater 90 to hydrotreat liquid fraction 22 may decrease an overall demand for water by hydrotreating system 30 when compared to a hydrotreating system that utilizes reforming apparatus 60 to produce hydrogen gas but does not utilize hydrogen gas from gaseous fraction 24 within hydrotreater 90. As an illustrative, non-exclusive example, and in a system that does not utilize hydrogen gas that is concentrated from gaseous fraction 24 of shale oil stream 20 to hydrotreat liquid fraction 22 of the shale oil stream, a ratio of a flow rate of water that is supplied to a reforming apparatus to produce hydrogen gas to a flow rate of the hydrotreated liquid stream that is produced by the hydrotreater may be greater than 0.7:1, greater than 0.75:1, greater than 0.8:1, greater than 0.9:1, or greater than 1:1.

[0035] In contrast, and when liquid fraction 22 is hydrotreated using the systems and methods according to the present disclosure, a ratio of the flow rate of water that is supplied to reforming apparatus 60 to the flow rate of hydrotreated liquid stream 92 may be less than 0.75:1, less than 0.7:1, less than 0.6:1, less than 0.5:1, less than 0.4:1, less than 0.3:1, less than 0.2:1, less than 0.1:1, less than 0.05:1, or substantially zero. This decrease in the flow rate of water that is needed to hydrotreat liquid fraction 22 may be due to the concentration of

hydrogen gas 46 from gaseous fraction 24 to supply a fraction, a majority, a substantial majority, or all of the hydrogen gas that is utilized by hydrotreater 90 to hydrotreat liquid fraction 22 and produce hydrotreated liquid stream 92.

[0036] Reforming apparatus 60 may produce reformat stream 62, which includes
5 hydrogen gas 46, from gaseous hydrocarbon stream 56 and/or from supplemental reactant stream 61, using any suitable method and/or mechanism. Illustrative, non-exclusive examples of reforming apparatus 60 according to the present disclosure include a stream reformer 64, a pressure swing reformer 65, an autothermal reformer 66, a partial oxidation reformer 67, and/or a preferential oxidation reformer 69. Illustrative, non-exclusive examples
10 of reforming apparatus that may be utilized with the systems and methods according to the present disclosure are disclosed in U.S. Patent Nos. 5,938,800, 5,998,053, 6,165,633, 7,217,303 and 7,491,250, the complete disclosures of which are hereby incorporated by reference.

[0037] As an illustrative, non-exclusive example, steam reformer 64 may be configured
15 to receive one or more carbon-containing compounds, such as methane and/or another hydrocarbon, and water, in the form of steam, as reactants. The steam reformer may catalytically react the water and the one or more carbon-containing compounds in an endothermic steam reforming reaction, and produce carbon monoxide and hydrogen gas therefrom. Subsequent to the steam reforming reaction, a water-gas-shift reactor may react
20 the produced carbon monoxide with additional water to produce carbon dioxide and hydrogen gas in an exothermic water-gas-shift reaction.

[0038] As another illustrative, non-exclusive example, pressure swing reformer 65 may utilize a cyclic reforming process to produce hydrogen gas from a hydrocarbon-containing feed stream. The pressure swing reformer may include one or more catalytic reactors that
25 include a first zone and a second zone that are in fluid communication with one another.

[0039] In a first step of the cyclic reforming process, the first zone is heated to a reforming temperature and a hydrocarbon, together with steam and optionally carbon dioxide, is introduced into a first port that is associated with the first zone of a catalytic reactor. The hydrocarbon feed reacts with the steam in an endothermic reforming reaction to produce
30 hydrogen gas and one or more other gasses, which flow through the second zone and exit the catalytic reactor through a second port that is associated with the second zone. Concurrently, the endothermic reforming reaction cools the first zone. The catalytic reactors may include

one or more catalyst beds, or regions, which optionally may include packed beds, or regions, of catalyst.

5 [0040] In a second step of the cyclic reforming process, a gas is introduced into the second zone, is heated by thermal contact with the catalytic materials present within the second zone, and flows to the first zone, thereby heating the first zone. Then, an oxygen-containing gas and a fuel are combusted near an interface region between the first zone and the second zone to further heat the first zone to the reforming temperature. Once the first zone reaches the reforming temperature, the first step of the cyclic reforming process may be repeated.

10 [0041] Sorptive separation assembly 70 may include and/or be any suitable structure that is configured to receive gaseous fraction 24 and/or purified gaseous fraction 54 and to produce concentrated hydrogen stream 74 therefrom. Illustrative, non-exclusive examples of sorptive separation assemblies 70 that may be utilized with the systems and methods according to the present disclosure include an absorptive separation assembly 75, an
15 adsorptive separation assembly 76, a pressure swing adsorption assembly 77, a rotary pressure swing adsorption assembly 78, and/or a rapid cycle pressure swing adsorption assembly 79. Illustrative, non-exclusive examples of sorptive separation assemblies are disclosed in U.S. Patent Nos. 7,037,358, 7,225,866, 7,405,243, and 7,591,879, the complete disclosures of which are hereby incorporated by reference.

20 [0042] Sorptive separation assembly 70 may include one or more sorption columns that may include, or contain, a sorptive media. The one or more sorption columns may be configured to receive supply stream 71 that includes gaseous fraction 24 and/or purified gaseous fraction 54 and to sorb, temporarily sorb, and/or reversibly sorb, one or more impurities 68 that may be present within the supply stream within the sorptive media while
25 providing for flow of hydrogen gas 46 therethrough.

[0043] It is within the scope of the present disclosure that sorptive separation assembly 70 may utilize a plurality of operational steps, or a cycle, to produce the concentrated hydrogen stream. Illustrative, non-exclusive examples of operational steps that may be utilized by the sorptive separation assembly include a pressurization step, an adsorption step,
30 a depressurization step, and a purge step. During the pressurization step, a pressure within the one or more sorption columns may be increased to a desired, or target, pressure, or pressure range. During the adsorption step, supply stream 71 may be provided to the one or more sorption columns and impurities 68 may be retained, or sorbed, therein, while hydrogen

gas may flow therethrough. During the depressurization step, the pressure within the one or more sorption columns may be decreased, which may release the sorbed impurities from the sorptive media. During the purge step, a purge gas may be provided to the one or more sorption columns to further remove the sorbed impurities from the sorptive media and/or from within the one or more sorption columns.

[0044] It is also within the scope of the present disclosure that sorptive separation assembly 70 may include and/or be a temperature swing adsorption assembly 80. Temperature swing adsorption assembly 80 may utilize a plurality of temperature swing operational steps, or a cycle, to produce the concentrated hydrogen stream. Illustrative, non-exclusive examples of temperature swing operational steps according to the present disclosure include a cooling step, an adsorption step, a heating step, and a purge step. The adsorption step and the purge step have been discussed in more detail herein. The cooling step may include cooling the one or more sorption columns to increase sorption of impurities 68 therewithin. Conversely, the heating step may include heating the one or more sorption columns to desorb the impurities.

[0045] It is within the scope of the present disclosure that concentrated hydrogen stream 74 may include any suitable portion, or fraction, of the hydrogen gas that is present within supply stream 71. As illustrative, non-exclusive examples, the concentrated hydrogen stream may include at least 60 mole%, at least 65 mole%, at least 70 mole%, at least 75 mole%, at least 80 mole%, at least 85 mole%, or at least 90 mole% of the hydrogen gas that is present within the supply stream.

[0046] As discussed in more detail herein, sorptive separation assembly 70 may be configured to receive supply stream 71, which includes hydrogen gas 46 and impurities 68, and to produce impurities stream 72 and concentrated hydrogen stream 74 therefrom. It is within the scope of the present disclosure that a concentration of hydrogen gas within the concentrated hydrogen stream may be greater than a concentration of hydrogen gas within the supply stream and/or the impurities stream. As illustrative, non-exclusive examples, the concentration of hydrogen gas within concentrated hydrogen stream 72 may be at least 60 mole%, at least 70 mole%, at least 80 mole%, at least 90 mole%, at least 95 mole%, or at least 99 mole%.

[0047] Similarly, it is also within the scope of the present disclosure that a concentration of impurities 68 within impurities stream 72 may be greater than a concentration of impurities 68 in the supply stream and/or the concentrated hydrogen stream. It is further within the

scope of the present disclosure that hydrotreating system 30 and/or shale oil production site 10 may include and/or be in fluid communication with an injection assembly that is configured to inject impurities stream 72 into the subterranean formation and/or a combustion assembly that is configured to combust the impurities stream.

5 **[0048]** Hydrotreater 90 may include and/or be any suitable structure that is configured to receive liquid fraction 22, to react liquid fraction 22 with hydrogen gas 46 from concentrated hydrogen stream 74 and/or reformat stream 62, and to produce hydrotreated liquid stream 92 therefrom. Hydrotreater 90 may utilize a hydrotreating, or hydrogenation, reaction to saturate olefinic materials (alkenes and alkynes) that may be present within liquid fraction 22 and
10 thereby to convert at least a portion of the olefinic materials into paraffinic materials (alkanes). It is within the scope of the present disclosure that the portion of the olefinic materials may include at least 50%, at least 60%, at least 70%, at least 80%, at least 90%, at least 95%, at least 99%, or substantially all of the olefinic materials.

[0049] Hydrogenation is generally described to be a catalytic reaction that may be
15 performed in the presence of a catalyst and adds hydrogen to carbon-carbon double and/or triple bonds, thereby converting the olefinic materials into paraffinic materials. Illustrative, non-exclusive examples of hydrotreaters 90 and/or hydrogenation reactions thereof are disclosed in U.S. Patent Nos. 3,865,716, 4,240,900, and 6,162,350, the complete disclosures of which are hereby incorporated by reference.

20 **[0050]** Hydrotreater 90 may be configured to provide hydrotreated liquid stream 92 to a pipeline 94. It is within the scope of the present disclosure that hydrotreated liquid stream 92 may be transferred, pumped, and/or conveyed any suitable distance through pipeline 94 without solidification, without significant solidification, and/or without substantial solidification therein. Additionally or alternatively, the hydrotreated liquid stream may be
25 transferred through pipeline 94 without blocking and/or occluding pipeline 94 due to solidification therein that may be caused by reaction, agglomeration, solidification, gumming, and/or gelling of olefinic materials that may be present within the hydrotreated liquid stream. In contrast, and were liquid fraction 22 to be provided directly to pipeline 94, the pipeline may be blocked and/or occluded by reaction, agglomeration, solidification, gumming, and/or
30 gelling of olefinic materials that may be present within the liquid fraction.

[0051] Hydrotreated liquid stream 92 includes a lower concentration of unsaturated carbon bonds than a concentration of unsaturated carbon bonds within liquid fraction 22. As an illustrative, non-exclusive example, a mole fraction of unsaturated carbon bonds and/or

olefinic material within hydrotreated liquid stream 92 may be less than 5%, less than 4%, less than 3%, less than 2%, less than 1%, less than 0.05%, or less than 0.01%. Additionally or alternatively, a chemical reactivity of hydrotreated liquid stream 92 may be less than a chemical reactivity of liquid fraction 22, such as due to the lower relative concentration of olefinic materials therein.

[0052] Fig. 2 is a flowchart depicting methods 200 according to the present disclosure of hydrotreating a liquid fraction of a shale oil stream using hydrogen gas that is obtained from a gaseous fraction of the shale oil stream. The methods may include generating a shale oil stream from a hydrocarbon well at 205 and include separating the shale oil stream into a liquid fraction and a gaseous fraction at 210. The methods also may include separating contaminants from the gaseous fraction at 215 and separating a gaseous hydrocarbon stream from the gaseous fraction at 220. The methods further include providing a portion of the gaseous fraction to a sorptive separation assembly at 225, separating a concentrated hydrogen stream from the portion of the gaseous fraction at 230, and providing the concentrated hydrogen stream and the liquid fraction to a hydrotreater at 235. The methods also may include reforming the gaseous hydrocarbon stream to produce a reformat stream at 240, separating a second concentrated hydrogen stream from the reformat stream at 245, and providing a second hydrogen-containing stream to the hydrotreater at 250. The methods further include reacting the concentrated hydrogen stream and/or the second hydrogen-containing stream with the liquid fraction to produce a hydrotreated liquid stream at 255.

[0053] Generating the shale oil stream from the hydrocarbon well at 205 may include generating the shale oil stream in, and/or producing the shale oil stream from, any suitable subterranean formation that is in fluid communication with the hydrocarbon well. Additionally or alternatively, the generating also may include conveying, or producing, the shale oil stream from the subterranean formation with the hydrocarbon well. The hydrocarbon well may be part of an oil shale production site, and the subterranean formation may be or include a shale oil source.

[0054] When the shale oil stream is generated within the subterranean formation, it is within the scope of the present disclosure that the shale oil stream may be generated in any suitable manner. As illustrative, non-exclusive examples, the generating may include performing any suitable pyrolysis reaction, *in situ* pyrolysis reaction, shale oil retort process, shale oil heat treating process, hydrogenation reaction, thermal dissolution reaction, and/or *in situ* shale oil conversion process within the subterranean formation.

[0055] It is within the scope of the present disclosure that the method further may include transferring the generated shale oil stream from the hydrocarbon well to a hydrotreating assembly that is configured to perform at least the separating at 210, the separating at 230, and/or the reacting at 255. The transferring may take place over any suitable separation distance, illustrative, non-exclusive examples of which include separation distances of less than 10 km, less than 8 km, less than 6 km, less than 5 km, less than 4 km, less than 3 km, less than 2 km, less than 1 km, less than 0.5 km, less than 0.25 km, or less than 0.1 km. Additionally or alternatively, the transferring may take place without *in situ* and/or *ex situ* treatment of the shale oil stream to decrease a concentration of unsaturated carbon bonds therein prior to the transferring.

[0056] Separating the shale oil stream into the liquid fraction and the gaseous fraction at 210 may include separating the liquid fraction from the gaseous fraction with any suitable system, method, and/or structure, illustrative, non-exclusive examples of which are discussed herein. It is within the scope of the present disclosure that the liquid fraction of the shale oil stream may include any suitable proportion, or mole fraction, of olefinic materials, illustrative, non-exclusive examples of which are discussed herein. Similarly, it is also within the scope of the present disclosure that the gaseous fraction of the shale oil stream may include hydrogen gas, as well as other gasses, contaminants, and/or impurities. Illustrative, non-exclusive examples of these other gasses, contaminants, and/or impurities, as well as the concentration of hydrogen gas within the gaseous fraction, are discussed herein.

[0057] Separating contaminants from the gaseous fraction at 215 may include separating any suitable contaminant from the hydrogen gas that is present within the gaseous fraction using any suitable contaminant removal assembly. Illustrative, non-exclusive examples of contaminants and contaminant removal assemblies are discussed herein. Separating contaminants from the gaseous fraction also may include separating the gaseous hydrocarbon stream from the gaseous fraction at 220.

[0058] Providing a portion of the gaseous fraction of the shale oil stream to the sorptive separation assembly at 225 may include providing any suitable portion, fraction, and/or percentage of the gaseous fraction to the sorptive separation assembly. As illustrative, non-exclusive examples, the portion of the gaseous fraction may include the entire gaseous fraction, a majority of the gaseous fraction, and/or a remainder of the gaseous fraction after the contaminants and/or the gaseous hydrocarbon stream have been separated from the

gaseous fraction at 215 and/or 220, respectively. Illustrative, non-exclusive examples of sorptive separation assemblies are discussed herein.

5 **[0059]** Separating the concentrated hydrogen stream from the portion of the gaseous fraction at 230 may include separating the concentrated hydrogen stream from the portion of the gaseous fraction within the sorptive separation assembly. This may include separating at least 60 mole%, at least 70 mole%, at least 75 mole%, at least 80 mole%, at least 85 mole%, or at least 90 mole% of the hydrogen gas that is present within the gaseous fraction from the gaseous fraction to generate the concentrated hydrogen stream and/or producing the concentrated hydrogen stream from the sorptive separation assembly.

10 **[0060]** As discussed in more detail herein, it is within the scope of the present disclosure that the portion of the gaseous fraction that is provided to the sorptive separation assembly may include hydrogen gas and impurities. Under these conditions, the separating also may include generating an impurities stream with the sorptive separation assembly and producing, or discharging, the impurities stream from the sorptive separation assembly. When the
15 impurities stream is produced by the sorptive separation assembly, the method further may include providing the impurities stream to a combustion assembly and combusting the impurities stream and/or providing the impurities stream to an injection assembly and injecting the impurities stream into the subterranean formation.

20 **[0061]** Providing the concentrated hydrogen stream and the liquid fraction of the shale oil stream to the hydrotreater at 235 may include providing the streams with any suitable system, method, and/or conduit. As an illustrative, non-exclusive example, the concentrated hydrogen stream may be supplied directly from the sorptive separation assembly to the hydrotreater and/or the liquid fraction may be supplied to the hydrotreater immediately after separation from the gaseous fraction. As another illustrative, non-exclusive example, the
25 concentrated hydrogen stream and/or the liquid fraction of the shale oil stream may receive further treatment, may be combined with another stream, may be separated into two or more streams, and/or may be stored, at least temporarily, prior to being provided to the hydrotreater.

30 **[0062]** Reforming the gaseous hydrocarbon stream to produce the reformat stream at 240 may include providing the gaseous hydrocarbon stream that is separated from the gaseous fraction of the shale oil stream to any suitable reforming apparatus and producing the reformat stream with the reforming apparatus. Illustrative, non-exclusive examples of

reforming apparatus and/or reactions thereof that may be utilized with the system and methods according to the present disclosure are discussed herein.

[0063] Separating the second concentrated hydrogen stream from the reformat stream at 245 may include providing the reformat stream to any suitable separation and/or purification assembly to produce the second concentrated hydrogen stream. Illustrative, non-exclusive examples of separation and/or purification assemblies that may be utilized to produce the second concentrated hydrogen stream are discussed herein.

[0064] Providing the second hydrogen-containing stream to the hydrotreater at 250 may include providing any suitable hydrogen-containing stream to the hydrotreater to supplement the hydrogen gas that is provided by the concentrated hydrogen stream. As illustrative, non-exclusive examples, this may include providing the entire reformat stream, a majority of the reformat stream, a portion of the reformat stream, the second concentrated hydrogen stream, and/or any suitable supplemental hydrogen stream to the hydrotreater.

[0065] Reacting the concentrated hydrogen stream and/or the second hydrogen-containing stream with the liquid fraction of the shale oil stream to produce the hydrotreated liquid stream at 250 may include performing a hydrogenation reaction within the hydrotreater to decrease the concentration of olefinic materials within the liquid fraction of the shale oil stream and to produce the hydrotreated liquid stream therefrom. Illustrative, non-exclusive examples of hydrotreaters, hydrogenation reactions, and concentrations of olefinic materials in the liquid fraction and/or the hydrotreated liquid stream are discussed herein.

[0066] In the present disclosure, several of the illustrative, non-exclusive examples have been discussed and/or presented in the context of flow diagrams, or flow charts, in which the methods are shown and described as a series of blocks, or steps. Unless specifically set forth in the accompanying description, it is within the scope of the present disclosure that the order of the blocks may vary from the illustrated order in the flow diagram, including with two or more of the blocks (or steps) occurring in a different order and/or concurrently. It is also within the scope of the present disclosure that the blocks, or steps, may be implemented as logic, which also may be described as implementing the blocks, or steps, as logics. In some applications, the blocks, or steps, may represent expressions and/or actions to be performed by functionally equivalent circuits or other logic devices. The illustrated blocks may, but are not required to, represent executable instructions that cause a computer, processor, and/or other logic device to respond, to perform an action, to change states, to generate an output or display, and/or to make decisions.

[0067] As used herein, the term “and/or” placed between a first entity and a second entity means one of (1) the first entity, (2) the second entity, and (3) the first entity and the second entity. Multiple entities listed with “and/or” should be construed in the same manner, i.e., “one or more” of the entities so conjoined. Other entities may optionally be present other than the entities specifically identified by the “and/or” clause, whether related or unrelated to those entities specifically identified. Thus, as a non-limiting example, a reference to “A and/or B,” when used in conjunction with open-ended language such as “comprising” may refer, in one embodiment, to A only (optionally including entities other than B); in another embodiment, to B only (optionally including entities other than A); in yet another embodiment, to both A and B (optionally including other entities). These entities may refer to elements, actions, structures, steps, operations, values, and the like.

[0068] As used herein, the phrase “at least one,” in reference to a list of one or more entities should be understood to mean at least one entity selected from any one or more of the entity in the list of entities, but not necessarily including at least one of each and every entity specifically listed within the list of entities and not excluding any combinations of entities in the list of entities. This definition also allows that entities may optionally be present other than the entities specifically identified within the list of entities to which the phrase “at least one” refers, whether related or unrelated to those entities specifically identified. Thus, as a non-limiting example, “at least one of A and B” (or, equivalently, “at least one of A or B,” or, equivalently “at least one of A and/or B”) may refer, in one embodiment, to at least one, optionally including more than one, A, with no B present (and optionally including entities other than B); in another embodiment, to at least one, optionally including more than one, B, with no A present (and optionally including entities other than A); in yet another embodiment, to at least one, optionally including more than one, A, and at least one, optionally including more than one, B (and optionally including other entities). In other words, the phrases “at least one,” “one or more,” and “and/or” are open-ended expressions that are both conjunctive and disjunctive in operation. For example, each of the expressions “at least one of A, B and C,” “at least one of A, B, or C,” “one or more of A, B, and C,” “one or more of A, B, or C” and “A, B, and/or C” may mean A alone, B alone, C alone, A and B together, A and C together, B and C together, A, B and C together, and optionally any of the above in combination with at least one other entity.

[0069] In the event that any patents, patent applications, or other references are incorporated by reference herein and define a term in a manner or are otherwise inconsistent

with either the non-incorporated portion of the present disclosure or with any of the other incorporated references, the non-incorporated portion of the present disclosure shall control, and the term or incorporated disclosure therein shall only control with respect to the reference in which the term is defined and/or the incorporated disclosure was originally present.

5 **[0070]** As used herein the terms “adapted” and “configured” mean that the element, component, or other subject matter is designed and/or intended to perform a given function. Thus, the use of the terms “adapted” and “configured” should not be construed to mean that a given element, component, or other subject matter is simply “capable of” performing a given function but that the element, component, and/or other subject matter is specifically selected,
10 created, implemented, utilized, programmed, and/or designed for the purpose of performing the function. It is also within the scope of the present disclosure that elements, components, and/or other recited subject matter that is recited as being adapted to perform a particular function may additionally or alternatively be described as being configured to perform that function, and vice versa.

15 **[0071]** Illustrative, non-exclusive examples of systems and methods according to the present disclosure are presented in the following enumerated paragraphs. It is within the scope of the present disclosure that an individual step of a method recited herein, including in the following enumerated paragraphs, may additionally or alternatively be referred to as a “step for” performing the recited action.

20 A1. A method of hydrotreating a liquid fraction of a shale oil stream with hydrogen gas concentrated from a gaseous fraction of the shale oil stream, the method comprising:

 separating the liquid fraction of the shale oil stream from the gaseous fraction of the shale oil stream;

25 providing a portion of the gaseous fraction to a sorptive separation assembly;

 separating, in the sorptive separation assembly, a concentrated hydrogen stream from the portion of the gaseous fraction;

 providing the concentrated hydrogen stream and the liquid fraction to a hydrotreater;
and

reacting, in the hydrotreater, the concentrated hydrogen stream with the liquid fraction to produce a hydrotreated liquid stream.

A2. The method of paragraph A1, wherein the method further includes generating the shale oil stream in a subterranean formation, and optionally wherein the method further includes conveying the shale oil stream from the subterranean formation through a hydrocarbon well.

A3. The method of paragraph A2, wherein the generating includes performing at least one of a pyrolysis reaction, an *in situ* pyrolysis reaction, a shale oil retort process, a shale oil heat treating process, a hydrogenation reaction, a thermal dissolution process, and an *in situ* shale oil conversion process, and optionally wherein the performing includes performing within the subterranean formation.

A4. The method of any of paragraphs A1-A3, wherein the method further includes transferring the shale oil stream from a/the hydrocarbon well to a hydrotreating assembly that includes the sorptive separation assembly and the hydrotreater, and optionally wherein the transferring includes transferring over a transfer distance of less than 10 kilometers (km), less than 8 km, less than 6 km, less than 5 km, less than 4 km, less than 3 km, less than 2 km, less than 1 km, less than 0.5 km, less than 0.25 km, or less than 0.1 km.

A5. The method of paragraph A4, wherein the transferring includes transferring the shale oil stream from the hydrocarbon well to the hydrotreating assembly without prior treatment of the shale oil stream to decrease a concentration of unsaturated carbon bonds therein, and optionally wherein the prior treatment includes at least one of prior *in situ* treatment and prior *ex situ* treatment.

A6. The method of any of paragraphs A1-A5, wherein the gaseous fraction of the shale oil stream includes hydrogen gas and contaminants, and further wherein the method includes separating at least a portion of the contaminants from the gaseous fraction to produce the portion of the gaseous fraction prior to providing the portion of the gaseous

fraction to the sorptive separation assembly, and optionally wherein the contaminants include at least one of hydrogen sulfide, carbon dioxide, carbon monoxide, sulfur, arsenic, arsine, gaseous hydrocarbons, and hydrocarbons with more than 3 carbon atoms.

A7. The method of any of paragraphs A1-A6, wherein the method further
5 includes separating a gaseous hydrocarbon stream from the gaseous fraction and reforming the gaseous hydrocarbon stream in a reforming apparatus to produce a reformat stream.

A8. The method of paragraph A7, wherein the method further includes providing a portion of the reformat stream to the hydrotreater and reacting the portion of the reformat stream with the liquid fraction of the shale oil stream to generate the hydrotreated
10 liquid stream, optionally wherein the method further includes separating a second concentrated hydrogen stream from the reformat stream, optionally wherein the portion of the reformat stream includes at least one of the entire reformat stream, a majority of the reformat stream, and the second concentrated hydrogen stream, and further optionally wherein the separating a second concentrated hydrogen stream includes separating with the
15 sorptive separation assembly.

A9. The method of paragraph A8, wherein the method further includes reacting the portion of the reformat stream in a water-gas shift reactor to at least one of decrease a concentration of carbon monoxide therein and increase a concentration of hydrogen gas therein prior to providing the portion of the reformat stream to the
20 hydrotreater.

A10. The method of any of paragraphs A7-A8 when dependent from paragraph A6, wherein the separating at least a portion of the contaminants from the gaseous fraction of the shale oil stream includes separating the gaseous hydrocarbon stream from the gaseous fraction.

A11. The method of any of paragraphs A7-A10, wherein the gaseous hydrocarbon stream includes at least one of methane, ethane, propane, and one or more volatile hydrocarbons.

A12. The method of any of paragraphs A7-A11, wherein the gaseous
5 hydrocarbon stream includes methane.

A13. The method of any of paragraphs A7-A12, wherein the reforming apparatus includes at least one of a steam reformer, a pressure swing reformer, an autothermal reformer, a partial oxidation reformer, and a preferential oxidation reformer.

A14. The method of any of paragraphs A1-A13, wherein the sorptive
10 separation assembly includes at least one of a pressure swing adsorption assembly, a rotary pressure swing adsorption assembly, and a rapid cycle pressure swing adsorption assembly.

A15. The method of any of paragraphs A1-A14, wherein the sorptive separation assembly is configured to operate cyclically in a plurality of operational steps that include at least two, optionally at least three, and further optionally all, of a pressurization
15 step, an adsorption step, a depressurization step, and a purge step, and further wherein separating the concentrated hydrogen stream from the portion of the gaseous fraction includes cycling the sorptive separation assembly through the plurality of operational steps.

A16. The method of any of paragraphs A1-A15, wherein the gaseous fraction of the shale oil stream includes hydrogen gas, and further wherein the separating includes
20 separating at least 60 mole%, at least 65 mole%, at least 70 mole%, at least 75 mole%, at least 80 mole%, at least 85 mole%, or at least 90 mole% of the hydrogen gas from the gaseous fraction to produce the concentrated hydrogen stream.

A17. The method of any of paragraphs A1-A16, wherein the gaseous fraction of the shale oil stream includes hydrogen gas and impurities, wherein the separating includes
25 producing the concentrated hydrogen stream and producing an impurities stream from the gaseous fraction, wherein a concentration of hydrogen gas in the concentrated hydrogen

stream is greater than a concentration of hydrogen gas in the gaseous fraction, wherein a concentration of the impurities in the impurities stream is greater than a concentration of the impurities in the gaseous fraction, optionally wherein the method further includes providing the impurities stream to at least one of a combustion assembly configured to combust the
5 impurities stream and an injection assembly configured to inject the impurities stream into a/the subterranean formation, and further optionally wherein the method further includes at least one of combusting the impurities stream and injecting the impurities stream into the subterranean formation.

A18. The method of any of paragraphs A1-A17, wherein the method includes
10 hydrotreating the liquid fraction of the shale oil stream using less water than a comparable method that does not include the providing a portion of the gaseous fraction to sorptive separation assembly and the separating a concentrated hydrogen stream steps.

A19. The method of any of paragraphs A1-A18, wherein the method includes hydrotreating the liquid fraction of the shale oil stream using an overall water to liquid
15 hydrocarbon volumetric ratio that is less than 0.75:1, less than 0.7:1, less than 0.6:1, less than 0.5:1, less than 0.4:1, less than 0.3:1, less than 0.2:1, less than 0.1:1, or less than 0.05:1.

A20. The method of any of paragraphs A1-A19, wherein, subsequent to the reacting, the method further includes conveying the hydrotreated liquid stream from the hydrotreater with a pipeline.

20 B1. A system for hydrotreating a liquid fraction of a shale oil stream with hydrogen gas concentrated from a gaseous fraction of the shale oil stream, the system comprising:

a sorptive separation assembly configured to receive a portion of the gaseous fraction of the shale oil stream and to produce a concentrated hydrogen stream therefrom; and

a hydrotreater configured to receive the concentrated hydrogen stream and the liquid fraction of the shale oil stream, to react the concentrated hydrogen stream with the liquid fraction, and to produce a hydrotreated liquid stream therefrom.

5 B2. The system of paragraph B1, wherein the system is in fluid communication with, and optionally wherein the system includes, a hydrocarbon well configured to convey the shale oil stream from a subterranean formation.

B3. The system of paragraph B2, wherein the subterranean formation includes, and optionally is, a chemical reactor configured to generate the shale oil stream by at least one of a pyrolysis reaction, an *in situ* pyrolysis reaction, a shale oil retort process, a
10 shale oil heat treating process, a hydrogenation reaction, a thermal dissolution process, and an *in situ* shale oil conversion process.

B4. The system of any of paragraphs B2-B3, wherein a distance between a wellhead that is associated with the hydrocarbon well and a hydrotreating assembly that includes the sorptive separation assembly and the hydrotreater is less than 10 kilometers
15 (km), less than 8 km, less than 6 km, less than 5 km, less than 4 km, less than 3 km, less than 2 km, less than 1 km, less than 0.5 km, less than 0.25 km, or less than 0.1 km, and optionally wherein the system includes the wellhead.

B5. The system of paragraph B4, wherein the system is configured to transfer the shale oil stream from the wellhead to the hydrotreating assembly without at least
20 one of prior *in situ* treatment and prior *ex situ* treatment to decrease a concentration of unsaturated carbon bonds therein.

B6. The system of any of paragraphs B1-B5, wherein the gaseous fraction of the shale oil stream includes hydrogen gas and contaminants, wherein the system includes a contaminant removal assembly configured to decrease a concentration of the contaminants in
25 the gaseous fraction and to produce a purified gaseous fraction therefrom, optionally wherein the contaminant removal assembly is configured provide the purified gaseous fraction to the

sorptive separation assembly, and further optionally wherein the contaminants includes at least one of hydrogen sulfide, carbon dioxide, carbon monoxide, sulfur, arsenic, arsine, gaseous hydrocarbons, and hydrocarbons with more than 3 carbon atoms.

5 B7. The system of any of paragraphs B1-B6, wherein the system further includes a reforming apparatus configured to receive a gaseous hydrocarbon stream and to produce a reformat stream therefrom, wherein the hydrotreater is configured to receive a portion of the reformat stream, to react the portion of the reformat stream with the liquid fraction of the shale oil stream, and to generate the hydrotreated liquid stream therefrom.

10 B8. The system of paragraph B7 when dependent from paragraph B6, wherein the contaminant removal assembly is configured to generate the purified gaseous fraction and the gaseous hydrocarbon stream from the gaseous fraction of the shale oil stream and to provide the gaseous hydrocarbon stream to the reforming apparatus.

15 B9. The system of any of paragraphs B7-B8, wherein the gaseous hydrocarbon stream includes at least one of methane, ethane, propane, and one or more volatile hydrocarbons.

B10. The system of any of paragraphs B7-B9, wherein the gaseous hydrocarbon stream includes methane.

20 B11. The system of any of paragraphs B7-B10, wherein the reforming apparatus includes at least one of a steam reformer, a pressure swing reformer, an autothermal reformer, a partial oxidation reformer, and a preferential oxidation reformer.

25 B12. The system of any of paragraphs B7-B11, wherein the system further includes a water-gas shift reactor configured to receive the reformat stream from the reforming apparatus and to at least one of reduce a concentration of carbon monoxide therein and increase a concentration of hydrogen gas therein and to generate the portion of the reformat stream.

B13. The system of any of paragraphs B7-B12, wherein the reforming apparatus is configured to provide the reformat stream to a separation assembly configured to increase a concentration of hydrogen gas in the reformat stream and to generate the portion of the reformat stream, and optionally wherein the separation assembly includes the
5 sorptive separation assembly.

B14. The system of any of paragraphs B1-B13, wherein the system further includes a liquid-gas separator configured to receive the shale oil stream and to produce the liquid fraction and the gaseous fraction therefrom.

B15. The system of any of paragraphs B1-B14, wherein the sorptive
10 separation assembly includes at least one of a pressure swing adsorption assembly, a rotary pressure swing adsorption assembly, and a rapid cycle pressure swing adsorption assembly.

B16. The system of any of paragraphs B1-B15, wherein the sorptive separation assembly is configured to be operated cyclically in a plurality of operational steps that include at least two, optionally at least three, and further optionally all, of a
15 pressurization step, an adsorption step, a depressurization step, and a purge step.

B17. The system of any of paragraphs B1-B16, wherein the gaseous fraction of the shale oil stream includes hydrogen gas, and further wherein the concentrated hydrogen stream includes at least 60 mole%, at least 65 mole%, at least 70 mole%, at least 75 mole%, at least 80 mole%, at least 85 mole%, or at least 90 mole% of the hydrogen gas from the
20 gaseous fraction.

B18. The system of any of paragraphs B1-B17, wherein the gaseous fraction of the shale oil stream includes hydrogen gas and impurities, wherein the sorptive separation assembly is configured to produce the concentrated hydrogen stream and an impurities stream from the gaseous fraction, wherein a concentration of hydrogen gas in the concentrated
25 hydrogen stream is greater than a concentration of hydrogen gas in the gaseous fraction, wherein a concentration of the impurities in the impurities stream is greater than a

concentration of the impurities in the gaseous fraction, and optionally wherein the system further includes at least one of a combustion assembly configured to combust the impurities stream and an injection assembly configured to inject the impurities stream into a/the subterranean formation.

5 B19. The system of any of paragraphs B1-B18, wherein the system is configured to hydrotreat the liquid fraction of the shale oil stream using less water than a comparable system that does not include the sorptive separation assembly.

 B20. The system of any of paragraphs B1-B19, wherein the system is configured to hydrotreat the liquid fraction of the shale oil stream using an overall water to
10 liquid hydrocarbon volumetric ratio that is less than 0.75:1, less than 0.7:1, less than 0.6:1, less than 0.5:1, less than 0.4:1, less than 0.3:1, less than 0.2:1, less than 0.1:1, or less than 0.05:1.

 B21. The system of any of paragraphs B1-B20, wherein the system is in fluid communication with, and optionally includes, a pipeline configured to convey the
15 hydrotreated liquid stream from the hydrotreater, wherein the hydrotreater is configured to provide the hydrotreated liquid stream to the pipeline, and further wherein the system is configured to decrease a potential for the formation of at least one of a solid, a gum, and a gel within the pipeline.

 C1. The method of any of paragraphs A1-A20 or the system of any of
20 paragraphs B1-B21, wherein the gaseous fraction of the shale oil stream includes 3-30 mole% hydrogen gas, and optionally wherein the gaseous fraction includes at least 3 mole%, at least 4 mole%, at least 5 mole%, at least 6 mole%, at least 8 mole%, at least 10 mole%, at least 12 mole% or at least 15 mole% hydrogen gas, and further optionally wherein the gaseous fraction includes less than 30 mole%, less than 28 mole%, less than 25 mole%, less than 22
25 mole%, less than 20 mole%, less than 18 mole%, less than 16 mole%, or less than 15 mole% hydrogen gas.

C2. The method of any of paragraphs A1-A20 or C1 or the system of any of paragraphs B1-C1, wherein the gaseous fraction of the shale oil stream includes at least one of a reservoir fluid, a gaseous hydrocarbon, a volatile hydrocarbon, and hydrogen gas, and optionally wherein the gaseous fraction includes hydrogen gas and at least one of a reservoir
5 fluid, a gaseous hydrocarbon, and a volatile hydrocarbon, and further optionally wherein the gaseous fraction includes hydrogen gas and methane.

C3. The method of any of paragraphs A1-A20 or C1-C2 or the system of any of paragraphs B1-C2, wherein the liquid fraction of the shale oil stream includes at least one of a/the reservoir fluid, a liquid hydrocarbon, a light oil, one or more olefins, one or more
10 alkenes, and one or more alkynes.

C4. The method of any of paragraphs A1-A20 or C1-C3 or the system of any of paragraphs B1-C3, wherein a mole fraction of unsaturated hydrocarbon molecules in the liquid fraction is less than 20%, less than 15%, less than 12.5%, less than 10%, less than 7.5%, or less than 5%, and further optionally wherein the mole fraction of unsaturated
15 hydrocarbon molecules in the liquid fraction is greater than 1%, greater than 2.5%, greater than 5%, greater than 7.5%, greater than 10%, greater than 12.5%, or greater than 15%.

C5. The method of any of paragraphs A1-A20 or C1-C4 or the system of any of paragraphs B1-C4, wherein the shale oil stream includes at least one of a/the reservoir fluid, kerogen, aged kerogen, the gaseous fraction, and the liquid fraction.
20

C6. The method of any of paragraphs A1-A20 or C1-C5 or the system of any of paragraphs B1-C5, wherein a concentration of unsaturated carbon bonds in the hydrotreated liquid stream is less than a concentration of unsaturated carbon bonds in the liquid fraction of the shale oil stream.

C7. The method of any of paragraphs A1-A20 or C1-C6 or the system of any of paragraphs B1-C6, wherein the hydrotreated liquid stream is configured to be pumped
25 through a pipeline without solidification therein.

C8. The method of any of paragraphs A1-A20 or C1-C7 or the system of any of paragraphs B1-C7, wherein a chemical reactivity of the hydrotreated liquid stream is less than a chemical reactivity of the liquid fraction of the shale oil stream.

C9. The method of any of paragraphs A1-A20 or C1-C8 or the system of any
5 of paragraphs B1-C8, wherein a mole fraction of unsaturated hydrocarbon molecules in the hydrotreated liquid stream is less than 5%, less than 4%, less than 3%, less than 2%, less than 1%, less than 0.05%, or less than 0.01%.

C10. The method of any of paragraphs A1-A20 or C1-C9 or the system of any of paragraphs B1-C9, wherein the concentrated hydrogen stream includes at least one of a
10 greater concentration of hydrogen gas and a lower concentration of the other gasses than the gaseous fraction of the shale oil stream.

C11. The method of any of paragraphs A1-A20 or C1-C10 or the system of any of paragraphs B1-C10, wherein a concentration of hydrogen gas within the concentrated hydrogen stream is at least 60 mole%, at least 70 mole%, at least 80 mole%, at least 90
15 mole%, at least 95 mole%, or at least 99 mole%.

D1. The use of any of the methods of any of paragraphs A1-A20 or C1-C9 with any of the systems of any of paragraphs B1-C9.

D2. The use of any of the systems of any of paragraphs B1-C9 with any of the methods of any of paragraphs A1-A20 or C1-C9.

20 D3. The use of any of the methods of any of paragraphs A1-A20 or C1-C9 or any of the systems of any of paragraphs B1-C9 to hydrotreat a shale oil stream.

D4. The use of any of the methods of any of paragraphs A1-A20 or C1-C9 or any of the systems of any of paragraphs B1-C9 to pre-treat a shale oil stream prior to transferring the shale oil stream with a pipeline.

D5. The use of a sorptive separation assembly at a production site to produce a concentrated hydrogen stream that is used to hydrotreat a liquid fraction of a shale oil stream.

D6. The use of a sorptive separation assembly at a production site to produce
5 a concentrated hydrogen stream from a gaseous fraction of a shale oil stream, wherein the concentrated hydrogen stream is used to hydrotreat a liquid fraction of the shale oil stream.

E1. A hydrotreated shale oil stream produced by the methods of any of paragraphs A1-A20 and C1-C11, the systems of any of paragraphs B1-C11, and/or the uses of any of paragraphs D1-D6.

E2. Shale oil produced using the methods of any of paragraphs A1-A20 and
10 C1-C11, the systems of any of paragraphs B1-C11, and/or the uses of any of paragraphs D1-D6.

PCT1. A method of hydrotreating a liquid fraction of a shale oil stream with hydrogen gas concentrated from a gaseous fraction of the shale oil stream, the method
15 comprising:

separating the liquid fraction of the shale oil stream from the gaseous fraction of the shale oil stream;

providing a portion of the gaseous fraction to a sorptive separation assembly;

separating, in the sorptive separation assembly, a concentrated hydrogen stream from
20 the portion of the gaseous fraction;

providing the concentrated hydrogen stream and the liquid fraction to a hydrotreater;
and

reacting, in the hydrotreater, the concentrated hydrogen stream with the liquid fraction to produce a hydrotreated liquid stream.

PCT2. The method of paragraph PCT1, wherein the method further includes
25 generating the shale oil stream within a subterranean formation using at least one of a

pyrolysis reaction, an *in situ* pyrolysis reaction, a shale oil retort process, a shale oil heat treating process, a hydrogenation reaction, a thermal dissolution process, and an *in situ* shale oil conversion process, and further wherein the method includes conveying the shale oil stream from the subterranean formation through a hydrocarbon well.

5 PCT3. The method of paragraph PCT2, wherein the method further includes transferring the shale oil stream from the hydrocarbon well to a hydrotreating assembly that includes the sorptive separation assembly and the hydrotreater, wherein the transferring includes transferring over a transfer distance of less than 5 km, and further wherein the transferring includes transferring the shale oil stream from the hydrocarbon well to the
10 hydrotreating assembly without prior treatment of the shale oil stream to decrease a concentration of unsaturated carbon bonds therein.

 PCT4. The method of any of paragraphs PCT1-PCT3, wherein the method further includes separating a gaseous hydrocarbon stream from the gaseous fraction, reforming the gaseous hydrocarbon stream in a reforming apparatus to produce a reformat
15 stream, providing a portion of the reformat stream to the hydrotreater, and reacting the portion of the reformat stream with the liquid fraction of the shale oil stream to generate the hydrotreated liquid stream.

 PCT5. The method of paragraph PCT4, wherein the gaseous hydrocarbon stream includes methane.

20 PCT6. The method of any of paragraphs PCT4-PCT5, wherein the reforming apparatus includes at least one of a steam reformer, a pressure swing reformer, an autothermal reformer, a partial oxidation reformer, and a preferential oxidation reformer.

 PCT7. The method of any of paragraphs PCT1-PCT6, wherein the sorptive separation assembly includes at least one of a pressure swing adsorption assembly, a rotary
25 pressure swing adsorption assembly, and a rapid cycle pressure swing adsorption assembly.

PCT8. The method of any of paragraphs PCT1-PCT7, wherein the gaseous fraction of the shale oil stream includes 3-30 mole% hydrogen gas.

PCT9. A system for hydrotreating a liquid fraction of a shale oil stream with hydrogen gas concentrated from a gaseous fraction of the shale oil stream, the system
5 comprising:

a sorptive separation assembly configured to receive a portion of the gaseous fraction of the shale oil stream and to produce a concentrated hydrogen stream therefrom; and

a hydrotreater configured to receive the concentrated hydrogen stream and the liquid fraction of the shale oil stream, to react the concentrated hydrogen stream with the liquid
10 fraction, and to produce a hydrotreated liquid stream therefrom.

PCT10. The system of paragraph PCT9, wherein the system is in fluid communication with a hydrocarbon well configured to convey the shale oil stream from a subterranean formation, and further wherein the subterranean formation includes a chemical reactor configured to generate the shale oil stream by at least one of a pyrolysis reaction, an
15 *in situ* pyrolysis reaction, a shale oil retort process, a shale oil heat treating process, a hydrogenation reaction, a thermal dissolution process, and an *in situ* shale oil conversion process.

PCT11. The system of paragraph PCT10, wherein a distance between a wellhead that is associated with the hydrocarbon well and a hydrotreating assembly that includes the
20 sorptive separation assembly and the hydrotreater is less than 5 km, and further wherein the system is configured to transfer the shale oil stream from the wellhead to the hydrotreating assembly without prior treatment to decrease a concentration of unsaturated carbon bonds therein.

PCT12. The system of any of paragraphs PCT9-PCT11, wherein the gaseous
25 fraction of the shale oil stream includes hydrogen gas and contaminants, wherein the system includes a contaminant removal assembly configured to decrease a concentration of the

contaminants in the gaseous fraction and to produce a purified gaseous fraction therefrom, wherein the contaminant removal assembly is configured provide the purified gaseous fraction to the sorptive separation assembly.

PCT13. The system of any of paragraphs PCT9-PCT12, wherein the system
5 further includes a reforming apparatus configured to receive a gaseous hydrocarbon stream and to produce a reformat stream therefrom, wherein the hydrotreater is configured to receive a portion of the reformat stream, to react the portion of the reformat stream with the liquid fraction of the shale oil stream, and to generate the hydrotreated liquid stream therefrom.

10 PCT14. The system of paragraph PCT13, wherein the reforming apparatus includes at least one of a steam reformer, a pressure swing reformer, an autothermal reformer, a partial oxidation reformer, and a preferential oxidation reformer, and further wherein the gaseous hydrocarbon stream includes methane that is separated from the gaseous fraction.

PCT15. The system of any of paragraphs PCT9-PCT14, wherein the sorptive
15 separation assembly includes at least one of a pressure swing adsorption assembly, a rotary pressure swing adsorption assembly, and a rapid cycle pressure swing adsorption assembly, and further wherein the gaseous fraction of the shale oil stream includes 3-30 mole% hydrogen gas.

Industrial Applicability

20 [0072] The systems and methods disclosed herein are applicable to the oil and gas industry.

[0073] It is believed that the disclosure set forth above encompasses multiple distinct inventions with independent utility. While each of these inventions has been disclosed in its preferred form, the specific embodiments thereof as disclosed and illustrated herein are not to
25 be considered in a limiting sense as numerous variations are possible. The subject matter of the inventions includes all novel and non-obvious combinations and subcombinations of the various elements, features, functions and/or properties disclosed herein. Similarly, where the

claims recite “a” or “a first” element or the equivalent thereof, such claims should be understood to include incorporation of one or more such elements, neither requiring nor excluding two or more such elements.

[0074] It is believed that the following claims particularly point out certain combinations and subcombinations that are directed to one of the disclosed inventions and are novel and non-obvious. Inventions embodied in other combinations and subcombinations of features, functions, elements and/or properties may be claimed through amendment of the present claims or presentation of new claims in this or a related application. Such amended or new claims, whether they are directed to a different invention or directed to the same invention, whether different, broader, narrower, or equal in scope to the original claims, are also regarded as included within the subject matter of the inventions of the present disclosure.

CLAIMS

1. A method of hydrotreating a liquid fraction of a shale oil stream with hydrogen gas concentrated from a gaseous fraction of the shale oil stream, the method comprising:

separating the liquid fraction of the shale oil stream from the gaseous fraction of the shale oil stream;

providing a portion of the gaseous fraction to a sorptive separation assembly;

separating, in the sorptive separation assembly, a concentrated hydrogen stream from the portion of the gaseous fraction;

providing the concentrated hydrogen stream and the liquid fraction to a hydrotreater;

and
reacting, in the hydrotreater, the concentrated hydrogen stream with the liquid fraction to produce a hydrotreated liquid stream.

2. The method of claim 1, wherein the method further includes generating the shale oil stream within a subterranean formation using at least one of a pyrolysis reaction, an *in situ* pyrolysis reaction, a shale oil retort process, a shale oil heat treating process, a hydrogenation reaction, a thermal dissolution process, and an *in situ* shale oil conversion process, and further wherein the method includes conveying the shale oil stream from the subterranean formation through a hydrocarbon well.

3. The method of claim 2, wherein the method further includes transferring the shale oil stream from the hydrocarbon well to a hydrotreating assembly that includes the sorptive separation assembly and the hydrotreater.

4. The method of claim 3, wherein the transferring includes transferring over a transfer distance of less than 5 km.

5. The method of claim 3, wherein the transferring includes transferring the shale oil stream from the hydrocarbon well to the hydrotreating assembly without prior treatment of the shale oil stream to decrease a concentration of unsaturated carbon bonds therein.

6. The method of claim 1, wherein the gaseous fraction of the shale oil stream includes hydrogen gas and contaminants, and further wherein the method includes separating at least a portion of the contaminants from the gaseous fraction to produce the portion of the gaseous fraction prior to providing the portion of the gaseous fraction to the sorptive
5 separation assembly.

7. The method of claim 1, wherein the method further includes separating a gaseous hydrocarbon stream from the gaseous fraction and reforming the gaseous hydrocarbon stream in a reforming apparatus to produce a reformat stream.

8. The method of claim 7, wherein the method further includes providing a portion of
10 the reformat stream to the hydrotreater and reacting the portion of the reformat stream with the liquid fraction of the shale oil stream to generate the hydrotreated liquid stream.

9. The method of claim 7, wherein the gaseous hydrocarbon stream includes methane.

10. The method of claim 7, wherein the reforming apparatus includes at least one of a steam reformer, a pressure swing reformer, an autothermal reformer, a partial
15 oxidation reformer, and a preferential oxidation reformer.

11. The method of claim 1, wherein the sorptive separation assembly includes at least one of a pressure swing adsorption assembly, a rotary pressure swing adsorption assembly, and a rapid cycle pressure swing adsorption assembly.

12. The method of claim 1, wherein the sorptive separation assembly is
20 configured to operate cyclically in a plurality of operational steps that include at least a pressurization step, an adsorption step, a depressurization step, and a purge step, and further wherein separating the concentrated hydrogen stream from the portion of the gaseous fraction includes cycling the sorptive separation assembly through the plurality of operational steps.

13. The method of claim 1, wherein the method includes hydrotreating the
25 liquid fraction of the shale oil stream using an overall water to liquid hydrocarbon volumetric ratio that is less than 0.5:1.

14. The method of claim 1, wherein the gaseous fraction of the shale oil stream includes 3-30 mole% hydrogen gas.

15. A system for hydrotreating a liquid fraction of a shale oil stream with hydrogen gas from a gaseous fraction of the shale oil stream, the system comprising:

5 a sorptive separation assembly configured to receive a portion of the gaseous fraction of the shale oil stream and to produce a concentrated hydrogen stream therefrom; and

a hydrotreater configured to receive the concentrated hydrogen stream and the liquid fraction of the shale oil stream, to react the concentrated hydrogen stream with the liquid fraction, and to produce a hydrotreated liquid stream therefrom.

10 16. The system of claim 15, wherein the system is in fluid communication with a hydrocarbon well configured to convey the shale oil stream from a subterranean formation, and further wherein the subterranean formation includes a chemical reactor configured to generate the shale oil stream by at least one of a pyrolysis reaction, an *in situ* pyrolysis reaction, a shale oil retort process, a shale oil heat treating process, a hydrogenation
15 reaction, a thermal dissolution process, and an *in situ* shale oil conversion process.

17. The system of claim 16, wherein a distance between a wellhead that is associated with the hydrocarbon well and a hydrotreating assembly that includes the sorptive separation assembly and the hydrotreater is less than 5 km.

18. The system of claim 17, wherein the system is configured to transfer the
20 shale oil stream from the wellhead to the hydrotreating assembly without prior treatment to decrease a concentration of unsaturated carbon bonds therein.

19. The system of claim 15, wherein the gaseous fraction of the shale oil stream includes hydrogen gas and contaminants, wherein the system includes a contaminant removal assembly configured to decrease a concentration of the contaminants in the gaseous
25 fraction and to produce a purified gaseous fraction therefrom, wherein the contaminant

removal assembly is configured provide the purified gaseous fraction to the sorptive separation assembly.

20. The system of claim 15, wherein the system further includes a reforming apparatus configured to receive a gaseous hydrocarbon stream and to produce a reformat
5 stream therefrom, wherein the hydrotreater is configured to receive a portion of the reformat stream, to react the portion of the reformat stream with the liquid fraction of the shale oil stream, and to generate the hydrotreated liquid stream therefrom.

21. The system of claim 20, wherein the gaseous hydrocarbon stream includes methane that is separated from the gaseous fraction.

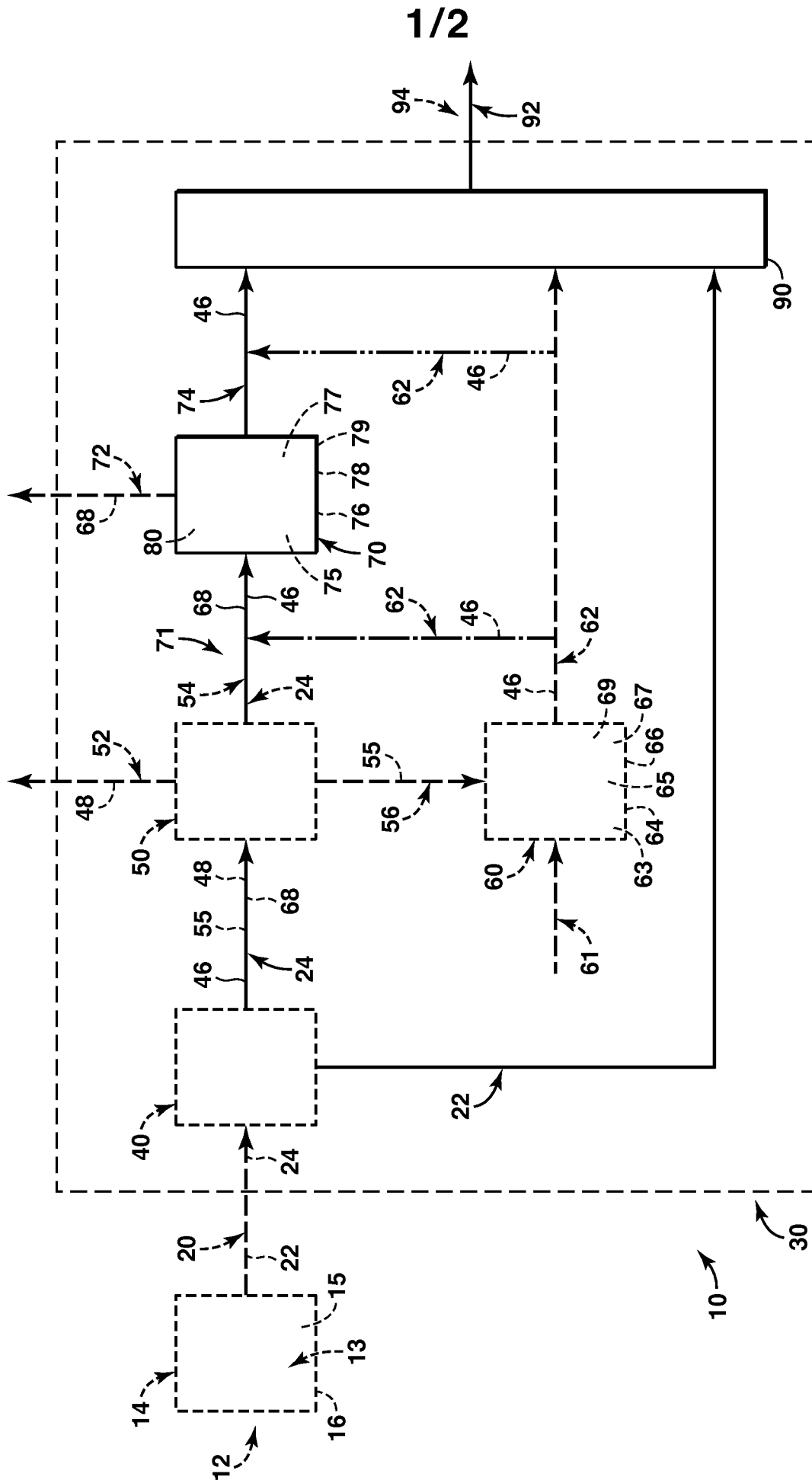
10 22. The system of claim 20, wherein the reforming apparatus includes at least one of a steam reformer, a pressure swing reformer, an autothermal reformer, a partial oxidation reformer, and a preferential oxidation reformer.

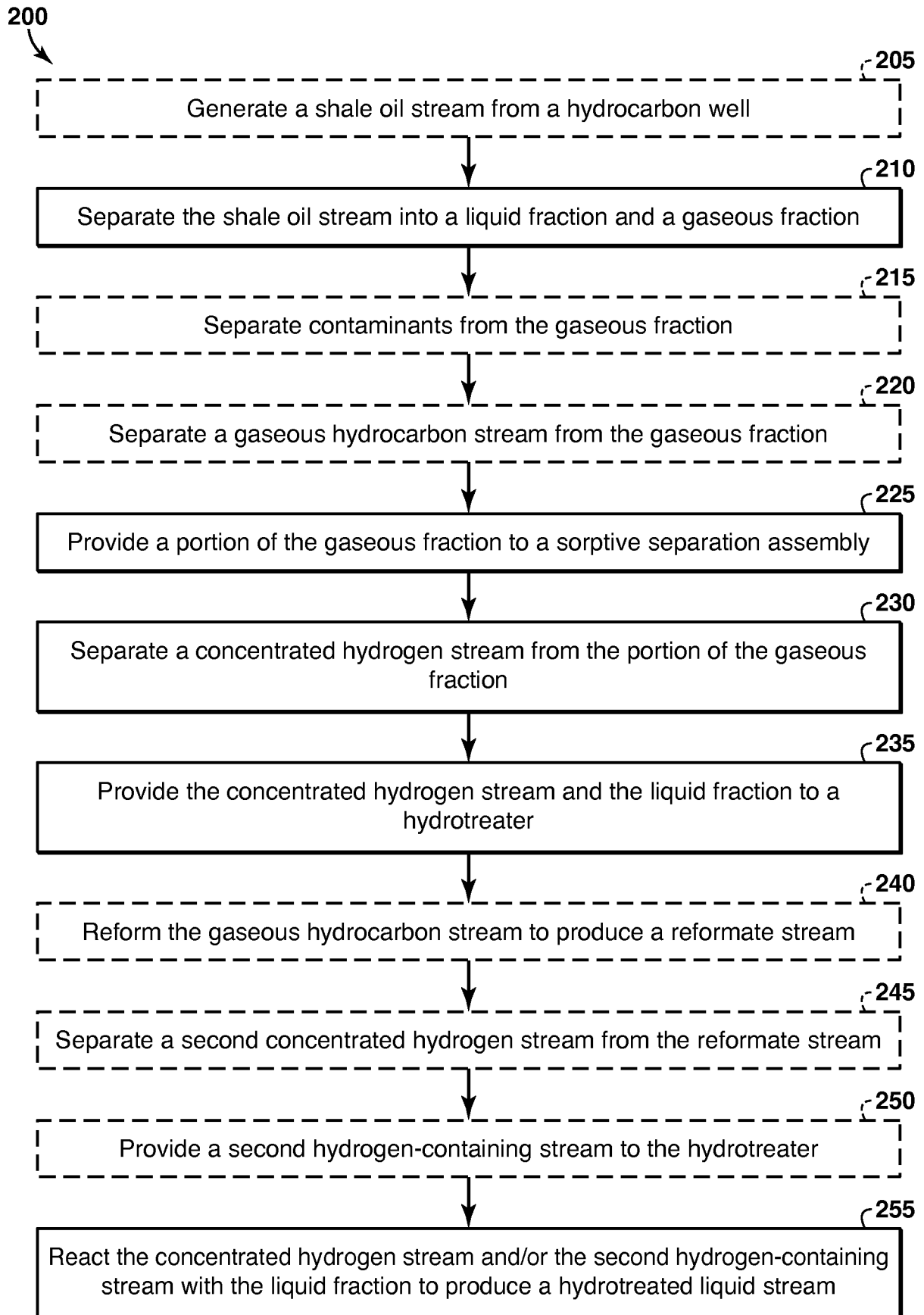
23. The system of claim 15, wherein the sorptive separation assembly includes at least one of a pressure swing adsorption assembly, a rotary pressure swing
15 adsorption assembly, and a rapid cycle pressure swing adsorption assembly.

24. The system of claim 15, wherein the sorptive separation assembly is configured to be operated cyclically in a plurality of operational steps that include at least a pressurization step, an adsorption step, a depressurization step, and a purge step.

25. The system of claim 15, wherein the system is configured to hydrotreat
20 the liquid fraction of the shale oil stream using an overall water to liquid hydrocarbon volumetric ratio that is less than 0.5:1.

26. The system of claim 15, wherein the gaseous fraction of the shale oil stream includes 3-30 mole% hydrogen gas.



2/2**FIG. 2**

INTERNATIONAL SEARCH REPORT

13/US3869-29-10-2013

International application No.

PCT/US2013/039869

A. CLASSIFICATION OF SUBJECT MATTER

IPC(8) - E21B 43/16 (2013.01)

USPC - 166/280.1

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) - E21B 43/16 (2013.01)

USPC - 166/280.1, 280.2, 281, 357, 251.1, 272.1, 302; 95/96, 102, 116; 208/56, 62, 69, 89, 99

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

CPC - E21B 43/16 (2013.01)

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

Orbit, PatFT, 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	US 4,353,418 A (HOEKSTRA et al) 12 October 1982 (12.10.1982) entire document	1-6, 13-19, 25, 26
Y		7-12, 20-24
Y	US 5,938,800 A (VERRILL et al) 17 August 1999 (17.08.1999) entire document	7-10, 20-22
Y	US 7,591,879 B2 (SUNDARAM et al) 22 September 2009 (22.09.2009) entire document	11, 12, 23, 24
A	US 7,225,866 B2 (BERCHENKO et al) 05 June 2007 (05.06.2007) entire document	1-26
A	US 2010/0276983 A1 (DUNN et al.) 04 November 2010 (04.11.2010), paragraphs [0079]-[0083]	4, 5, 17, 18



Further documents are listed in the continuation of Box C.



* Special categories of cited documents:

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"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

24 September 2013

Date of mailing of the international search report

29 OCT 2013

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