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(54) METHODS AND APPARATUS FOR LIQUEFACTION OF NATURAL GAS AND PRODUCTS THEREFROM

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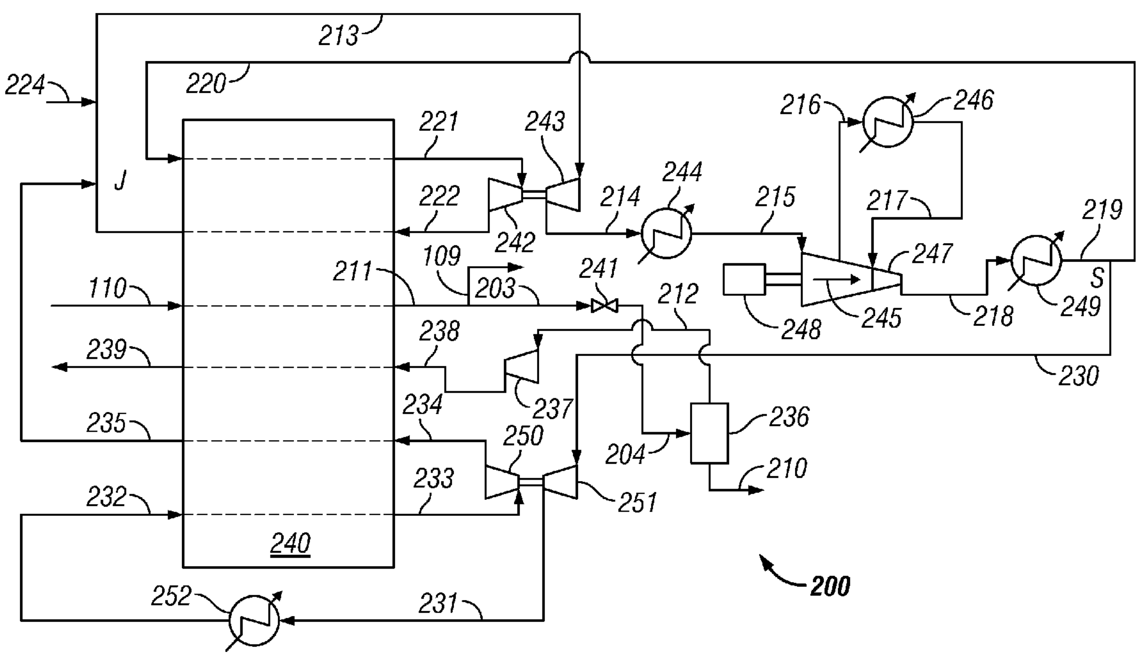
(57) ABSTRACT

A method for cooling natural gas with a refrigerant, one non-limiting embodiment which includes: (A) compressing and cooling the refrigerant to a first pressure to form a compressed refrigerant; (B) splitting the compressed refrigerant into a first stream and a second stream both at the first pressure; (C) cooling the first stream to form a cooled first stream; (D) expanding the cooled first stream to a first expansion pressure to form an expanded first stream; (E) compressing the second stream to a second pressure higher than the first pressure, forming a higher pressure second stream; (F) cooling the higher pressure second stream to form a cooled second stream; (G) expanding the cooled second stream to a second expansion pressure to form an expanded second stream; and, (H) Cooling the natural gas with the expanded first stream and expanded second stream, forming a cooled natural gas stream.



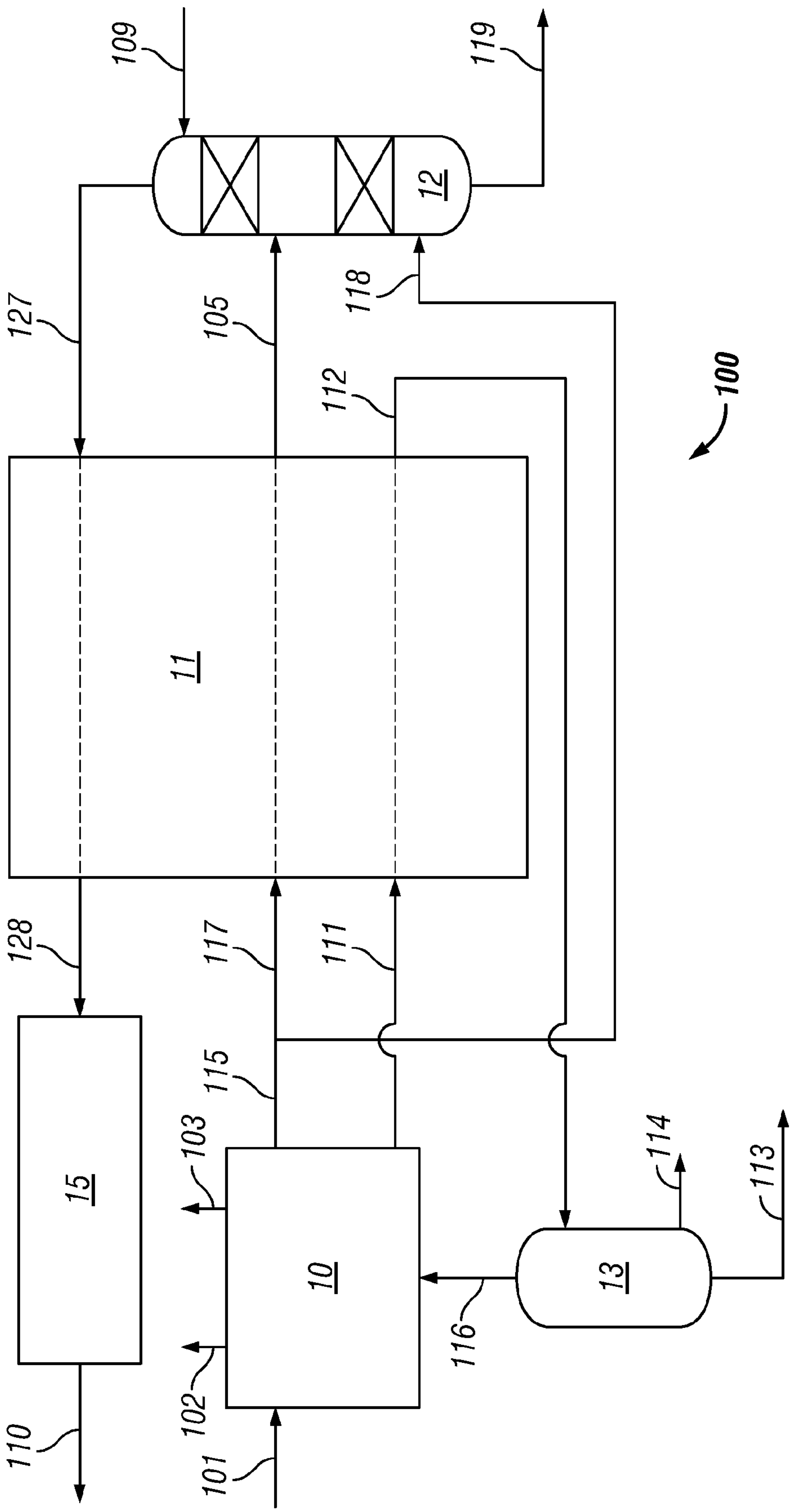

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FIG. 1

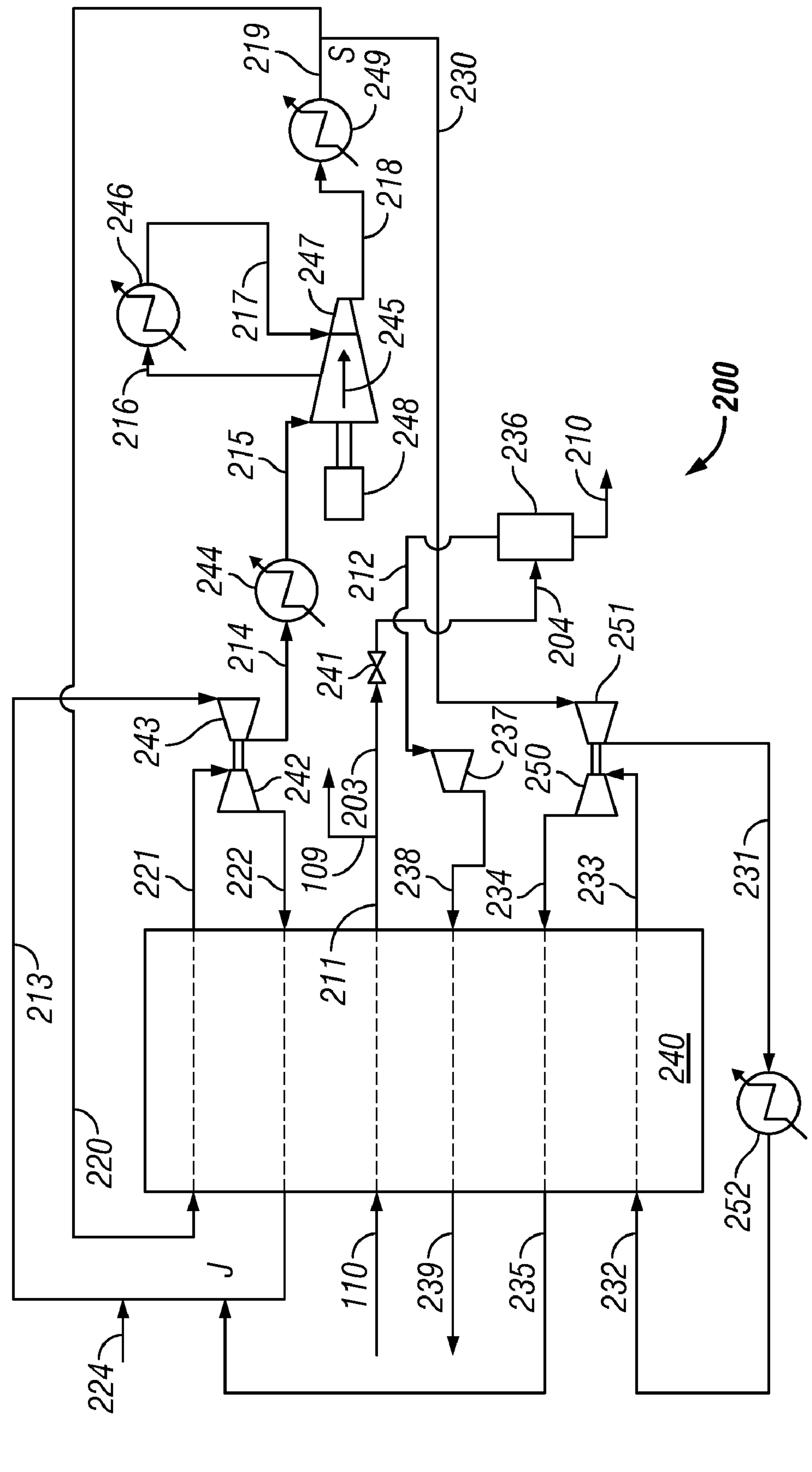
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FIG. 2

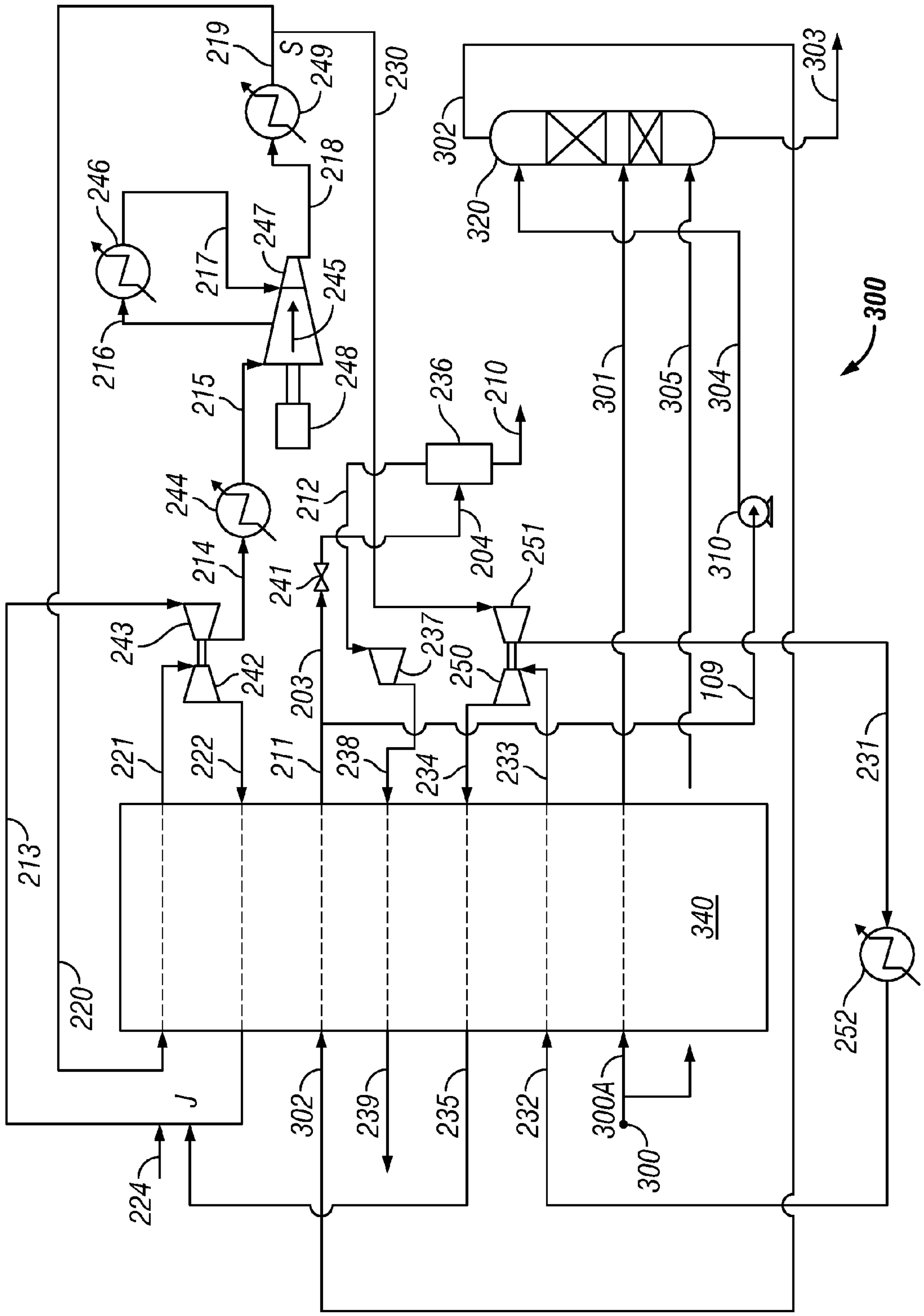
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FIG. 3

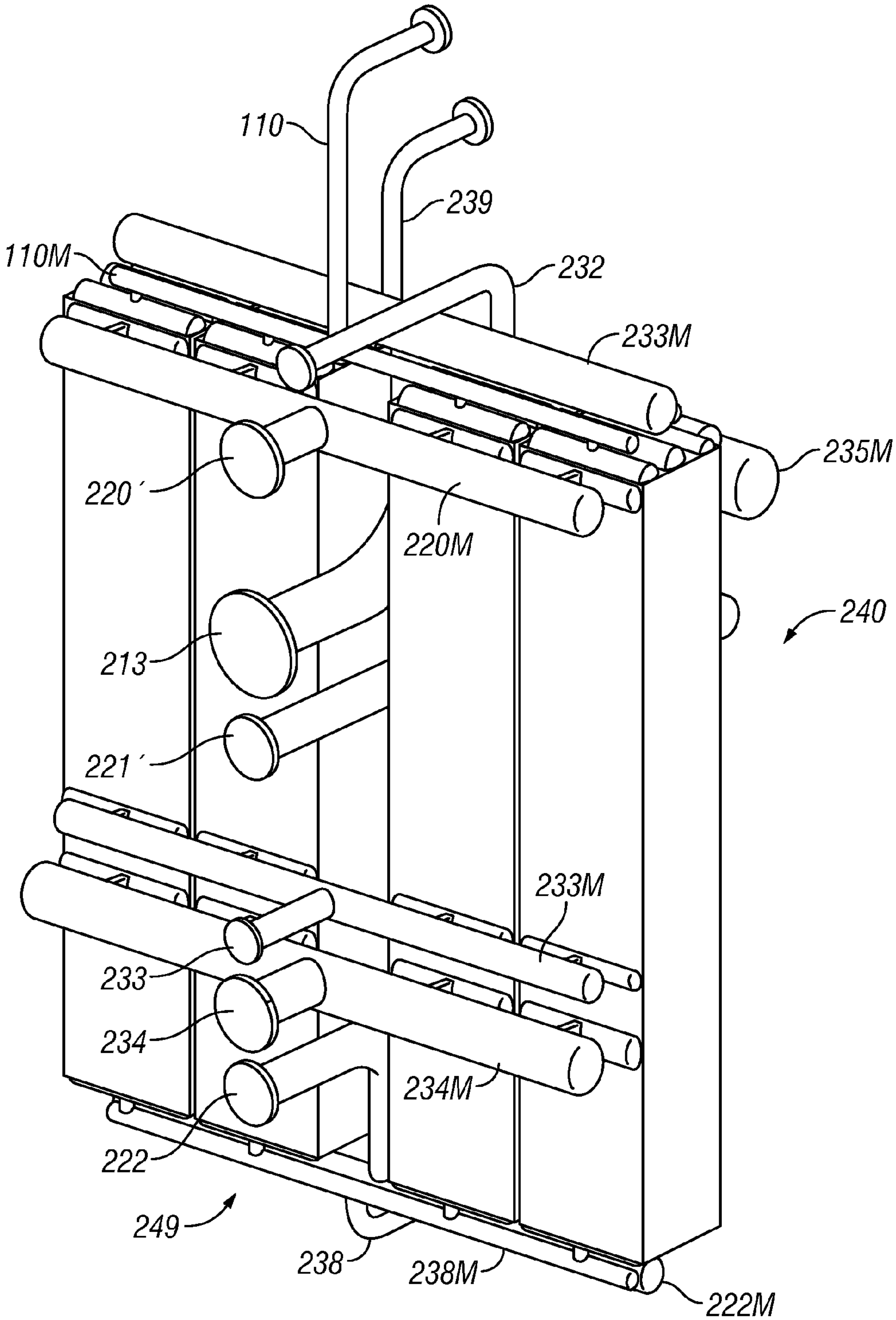
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FIG. 4

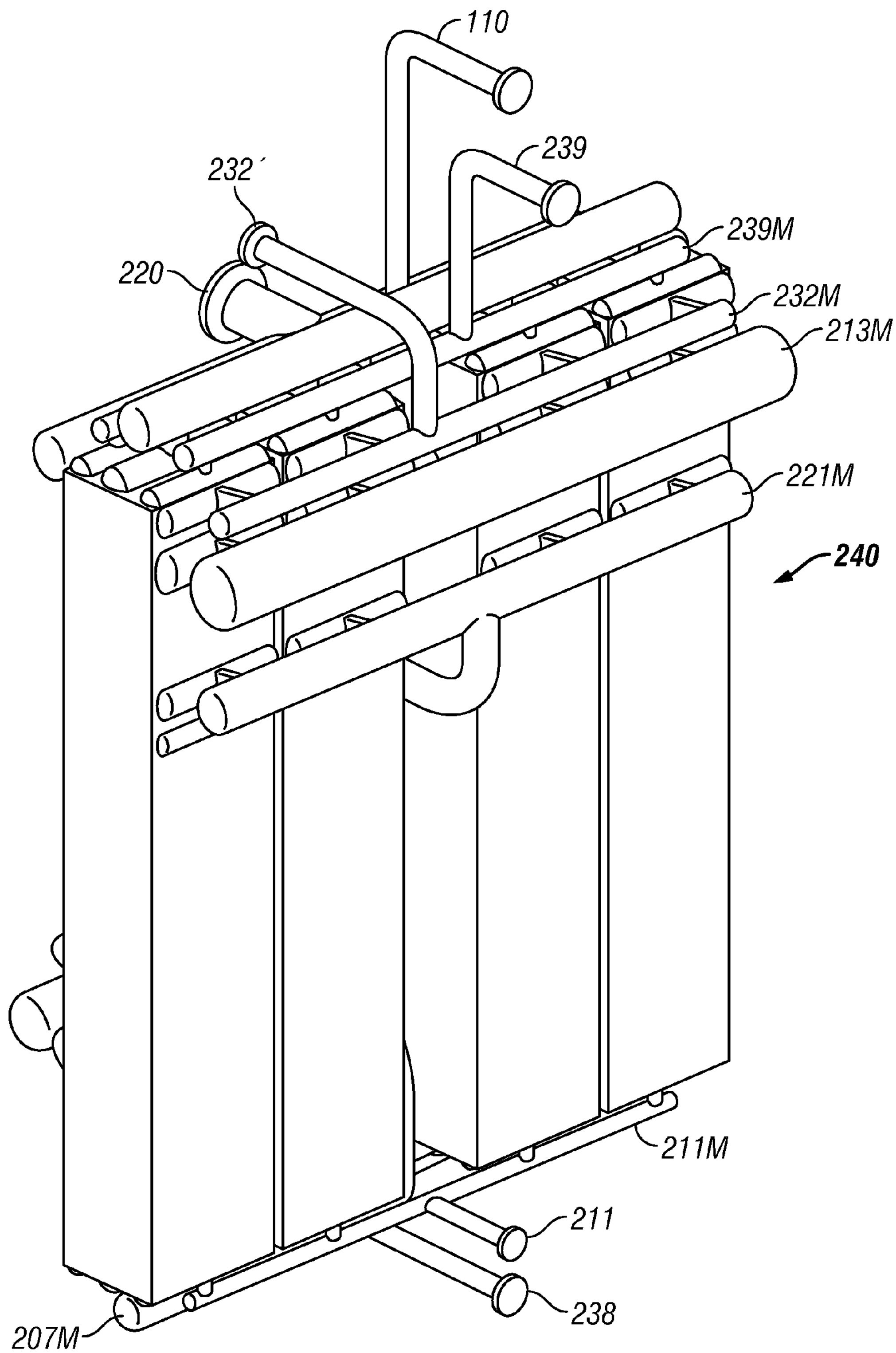

FIG. 5

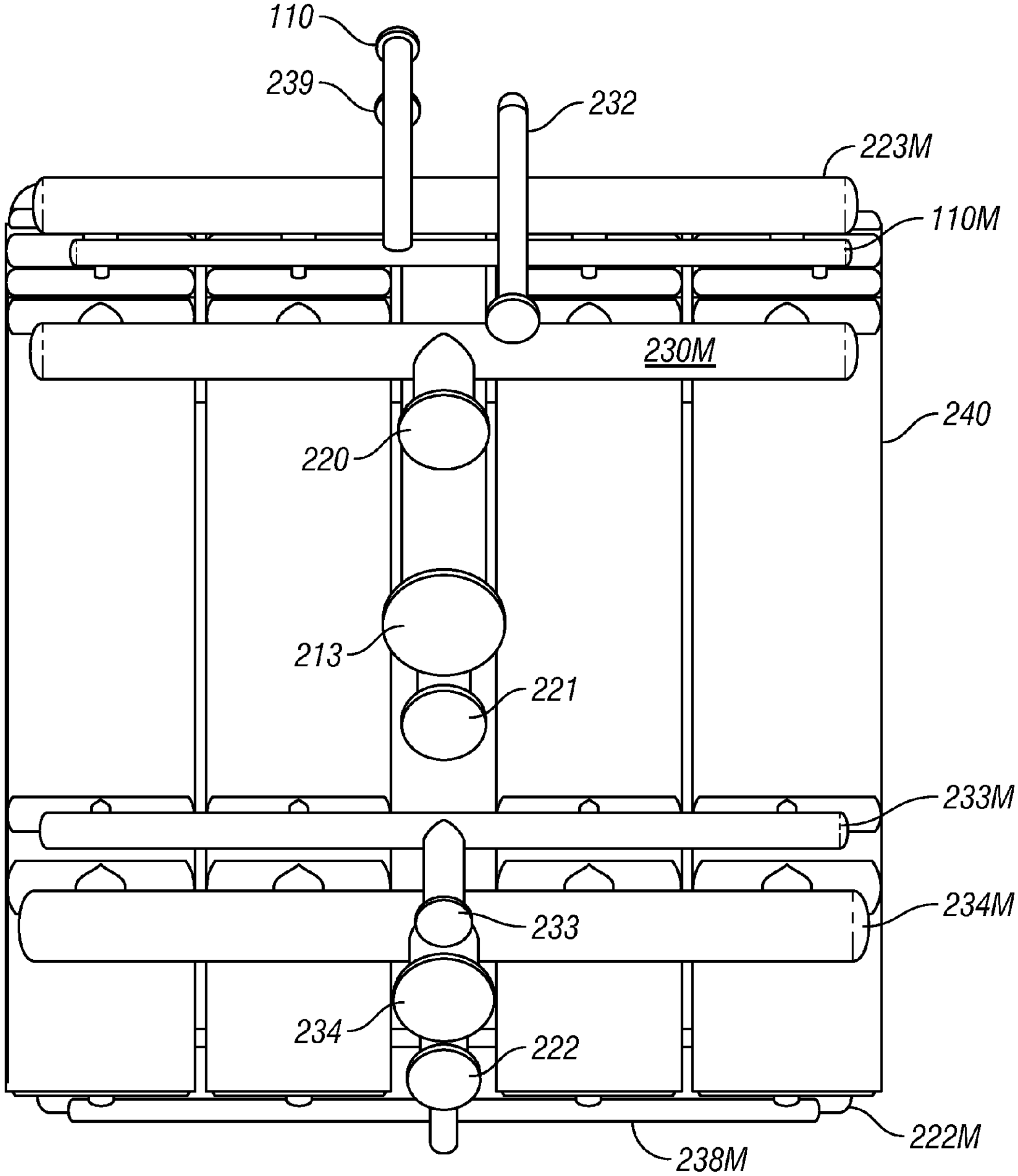
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FIG. 6

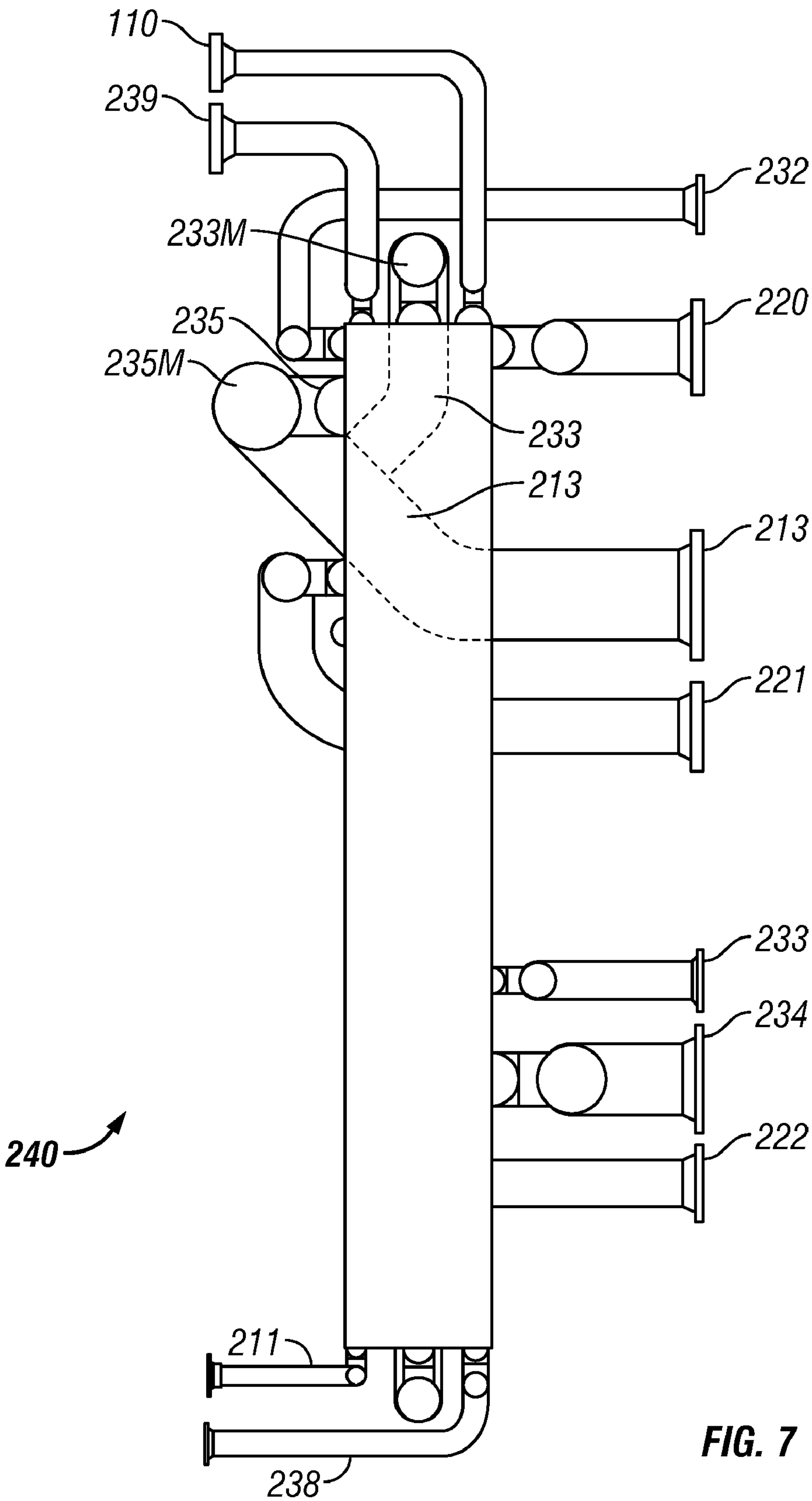
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FIG. 7

METHODS AND APPARATUS FOR LIQUEFACTION OF NATURAL GAS AND PRODUCTS THEREFROM

RELATED APPLICATION DATA.

[0001] This application claims priority of U.S. Provisional Patent Application No. 61/020,699, filed Jan. 14, 2008, and herein incorporated by reference.

BACKGROUND OF THE INVENTION

[0002] 1. Field of the Invention

[0003] The present invention relates to methods and apparatus for processing fluids and products therefrom. In another aspect, the present invention relates to liquefaction of gases and products therefrom. In even another aspect, the present invention relates to methods and apparatus for liquefaction of hydrocarbons and products therefrom. In still another aspect, the present invention relates to methods and apparatus for liquefaction of natural gas and products therefrom.

[0004] 2. Brief Description of the Related Art

[0005] Natural gas may come from a wide variety of sources. For example, the production of oil is many times accompanied by the production of natural gas. Historically, it is not unusual to flare this associated natural gas. More recently, regulatory, economic, and/or public relations considerations have generally dictated that this associated natural gas be disposed of in an acceptable manner, or recovered for sale or other use, such as, for example, as a fuel in the production process, or re-injected back into the formation to assist production. Other significant non-limiting examples of natural gas sources include stranded onshore or offshore gas fields or pipeline gas.

[0006] Where nearby processing infrastructure is available, recovery or proper disposal of associated gas is generally not an issue. However, in some locations, especially offshore locations, nearby processing infrastructure does not exist, and the regulatory and/or economic penalties related to associated gas processing, disposal or reinjection may make the oil recovery project economically unfeasible.

[0007] The liquefaction of natural gas to form liquefied natural gas (LNG) is generally accomplished by reducing the temperature of natural gas to a liquefaction temperature of about −250 F to about −260 F at or near atmospheric pressure. This liquefaction temperature range is typical for many natural gas streams because the boiling point of methane at atmospheric pressure is about −259 F. In order to produce, store and transport LNG, conventional processes known in the art require substantial refrigeration to liquefy and maintain natural gas at its liquefaction temperature. The most common of these refrigeration processes include: (1) the cascade process; (2) the single mixed refrigerant process; and (3) the propane pre-cooled mixed refrigerant process.

[0008] A cascade process produces LNG by employing several closed-loop cooling loops, each utilizing a single pure refrigerant and collectively configured in order of progressively lower temperatures. The first cooling circuit commonly utilizes propane or propylene as the refrigerant, the second circuit may utilize ethane or ethylene, while the third circuit generally utilizes methane as the refrigerant.

[0009] A single mixed refrigerant process produces LNG by employing a single closed-loop cooling circuit utilizing a multicomponent refrigerant consisting of components such as nitrogen, methane, ethane, propane, butanes and pentanes. The mixed refrigerant undergoes the steps of condensation, expansion and recompression to reduce the temperature of natural gas by employing a unitary collection of heat exchangers known as a “cold box.”

[0010] A propane pre-cooled mixed refrigerant process produces LNG by employing an initial series of propane-cooled heat exchangers in addition to a single closed-loop cooling circuit, which utilizes a multi-component refrigerant consisting of components such as nitrogen, methane, ethane and propane. Natural gas initially passes through one or more propane-cooled heat exchangers, proceeds to a main exchanger cooled by the multi-component refrigerant, and is thereafter expanded to produce LNG.

[0011] The following patents are merely a few of the many that address the processing of natural gas into liquefied natural gas.

[0012] U.S. Pat. No. 3,360,944 to Knapp et al. produces LNG by separating a natural gas feed stream into a major stream and a minor stream, cooling the major and minor streams to produce a liquid component, and thereafter using a substantial portion of the liquid component as a refrigerant for the process. The liquid component is vaporized while undergoing heat exchange, compressed and discharged from the process. The Knapp process results in only a minor portion of the natural gas feed stream processed into LNG.

[0013] U.S. Pat. No. 3,616,652 to Engal discloses a process for producing LNG in a single stage by compressing a natural gas feed stream, cooling the compressed natural gas feed stream to produce a liquefied stream, dramatically expanding the liquefied stream to an intermediate-pressure liquid, and then flashing and separating the intermediate-pressure liquid in a single separation step to produce LNG and a low-pressure flash gas. The low-pressure flash gas is recirculated, substantially compressed and reintroduced into the intermediate pressure liquid. While the Engal process produces LNG without the use of external refrigerants, the process inefficiently utilizes its limited refrigeration capacity upon the entire process stream without conjunctive use of multiple separation steps to offset this severe cooling requirement. Furthermore, the Engal process inefficiently expands its process stream pressure to a level that results in a substantial and highly inefficient recompression of its flash gas. Consequently, the Engal process yields a small volume of LNG compared to the amount of work required for its production, thus reducing the cost viability of the process.

[0014] U.S. Pat. No. 5,755,114 issued to Foglietta, discloses a hybrid liquefaction cycle for the production of LNG. The Foglietta process passes a pressurized natural gas feed stream into heat exchange contact with a closed-loop propane or propylene refrigeration cycle prior to directing the natural gas feed stream through a turboexpander cycle to provide auxiliary refrigeration. The Foglietta process can be implemented with only one closed-loop refrigeration cycle, as opposed to cascade type mixed refrigerant systems. However, the Foglietta process still requires at least one closed-loop refrigeration cycle comprising propane or propylene, both of which are explosive, not easily dispersed, and which must be stored and handled.

[0015] U.S. Pat. No. 5,768,912, issued Jun. 23, 1998, to Dubar, discloses a process for producing a liquefied natural product such as LNG where a single phase nitrogen refrigerant is used in such a way that the refrigerant stream is divided into at least two separate portions which are passed through separate turbo-expanders before being admitted to separate heat exchangers so that the warming curve of the refrigerant more closely matches the cooling curve of the product being liquefied so as to minimize thermodynamic inefficiencies and hence power requirements involved in operation of the method.

[0016] U.S. Pat. No. 5,791,160, issued Aug. 11, 1998, to Mandler et al., discloses a control system for a process of liquefied natural gas production (LNG) from natural gas using a heat exchanger and a closed loop refrigeration cycle employing independent, direct control of both production and temperature by adjusting refrigeration to match a set production. The control system sets and controls LNG production at a required production value, and independently controls LNG temperature by adjusting the refrigeration provided to the natural gas stream. One exemplary method employs compressor speed, for example, as a key manipulated variable (MV) to achieve fast and stable LNG temperature regulation. Other compressor variables rather than speed may be key MVs, depending on the type of MR compressors employed, and may be the guidevane angle in a centrifugal compressor or the stator blade angle in an axial compressor. The second exemplary method employs a ratio of total recirculating refrigerant flow to LNG flow as the key manipulated variable to effectively control the LNG temperature.

[0017] U.S. Pat. No. 5,916,260, issued Jun. 29, 1999, to Dubar discloses a natural gas liquefaction process comprising passing natural gas through a series of heat exchangers in countercurrent relationship with a gaseous refrigerant circulated through a work expansion cycle. The work expansion cycle comprises compressing the refrigerant, dividing and cooling the refrigerant to produce at least first and second cooled refrigerant streams, substantially isentropically expanding the first refrigerant stream to a coolest refrigerant temperature, substantially isentropically expanding the second refrigerant stream to an intermediate refrigerant temperature warmer than said coolest refrigerant temperature, and delivering the refrigerant in the first and second refrigerant streams to a respective heat exchanger for cooling the natural gas through corresponding temperature ranges. The refrigerant in the first stream is isentropically expanded to a pressure at least 10 times greater than the total pressure drop of the first refrigerant stream across said series of heat exchangers, said pressure being in the range of 1.2 to 2.5 MPa. While the Dubar process is effective, it is relatively complex, utilizing a number of heat exchangers manifolded in series. It utilizes a separate chilled water loop to cool both the inlet gas to the liquefaction process and the high-pressure refrigerant gas entering the liquefaction process. At pressures above about 5.5 MPa, the Dubar process utilizes a spiral wound heat exchanger, a PCHE, or a spool wound heat exchanger rather than an aluminum plate heat exchanger.

[0018] U.S. Pat. No. 6,023,942 to Thomas et al. discloses a process for producing a methane-rich liquid product having a temperature above about −112. degree. C. (−170.degree. F.) at a pressure that is sufficient for the liquid product to be at or below its bubble point. The resulting product is a pressurized liquid natural gas (“PLNG”), which has a pressure substantially above atmospheric pressure. While the Thomas et al. process can be implemented without external refrigeration, the product is pressurized requiring the use of specially designed heavy, thick-walled containers and transports (e.g., a PLNG ship, truck or railcar). This higher pressure, heavier walled equipment adds substantial weight and expense to any commercial project. The PLNG consumer will also require additional liquefaction, transport, and storage equipment to consume the PLNG, adding further cost to the supply and demand value chain.

[0019] U.S. Pat. No. 6,250,105, issued Jun. 26, 2001, to Kimble et al., discloses a process for liquefying natural gas to produce a pressurized liquid product having a temperature above −112. degree. C. using two mixed refrigerants in two closed cycles, a low-level refrigerant to cool and liquefy the natural gas and a high-level refrigerant to cool the low-level refrigerant. After being used to liquefy the natural gas, the low-level refrigerant is (a) warmed by heat exchange in countercurrent relationship with another stream of the low-level refrigerant and by heat exchange against a first stream of the high-level refrigerant, (b) compressed to an elevated pressure, and (c) aftercooled against an external cooling fluid. The low-level refrigerant is then cooled by heat exchange against a second stream of the high-level mixed refrigerant and by exchange against the low-level refrigerant. The high-level refrigerant is warmed by the heat exchange with the low-level refrigerant, compressed to an elevated pressure, and aftercooled against an external cooling fluid.

[0020] U.S. Pat. No. 6,298,688, issued Oct. 9, 2001, to Brostow et al., discloses a process for gas liquefaction, particularly nitrogen liquefaction, which combines the use of a nitrogen autorefrigeration cooling cycle with one or more closed-loop refrigeration cycles using two or more refrigerant components. The closed-loop refrigeration cycle or cycles provide refrigeration in a temperature range having a lowest temperature between about −125 F. and about −250 F. A nitrogen expander cycle provides additional refrigeration, a portion of which is provided at temperatures below the lowest temperature of the closed-loop or recirculating refrigeration cycle or cycles. The lowest temperature of the nitrogen expander cycle refrigeration range is between about −220 F. and about −320 F. The combined use of the two different refrigerant systems allows each system to operate most efficiently in the optimum temperature range, thereby reducing the power consumption required for liquefaction.

[0021] U.S. Pat. No. 6,389,844, issued May 21, 2002, to Voort et al., discloses a plant for liquefying natural gas comprising one pre-cooling heat exchanger having an inlet for natural gas and an outlet for cooled natural gas, a pre-cooling refrigerant circuit, one distributor having an inlet connected to the outlet for cooled natural gas and having two outlets, two main heat exchangers, and two main refrigerant loops each co-operating with one liquefaction heat exchanger.

[0022] U.S. Pat. No. 6,560,989, issued May 13, 2003, to Roberts et al., discloses a method for the recovery of hydrogen and one or more hydrocarbons having one or more carbon atoms from a feed gas containing hydrogen and the one or more hydrocarbons, which process comprises cooling and partially condensing the feed gas to provide a partially condensed feed; separating the partially condensed feed to provide a first liquid stream enriched in the one or more hydrocarbons and a first vapor stream enriched in hydrogen; further cooling and partially condensing the first vapor stream to provide an intermediate two-phase stream; and separating the intermediate two-phase stream to yield a further-enriched hydrogen stream and a hydrogen-depleted residual hydrocarbon stream. Some or all of the cooling is provided by indirect heat exchange with cold gas refrigerant generated in a closed-loop gas expander refrigeration cycle.

[0023] U.S. Pat. No. 6,564,578, issued May 20, 2003 to Fischer-Calderon, is directed to a process for producing LNG by directing a feed stream comprising natural gas to a cooling stage that (a) cools the feed stream in at least one cooling step producing a cooled feed stream, (b) expands the cooled feed stream in at least one expansion step by reducing the pressure of the cooled feed stream producing a refrigerated vapor component and a liquid component, and (c) separates at least a portion of the refrigerated vapor component from the liquid component wherein at least a portion of the cooling for the process is derived from at least a portion of the refrigerated vapor component; and repeating steps (a) through (c) one or more times until at least substantial portion of the feed stream in the first cooling stage is processed into LNG wherein the feed stream in step (a) comprises at least a portion of the liquid component produced from a previous cooling stage.

[0024] U.S. Pat. No. 6,672,104, issued Jan. 6, 2004, to Kimble et al. discloses a process for converting a boil-off stream comprising methane to a liquid having a preselected bubble point temperature. The boil-off stream is pressurized, then cooled, and then expanded to further cool and at least partially liquefy the boil-off stream. The preselected bubble point temperature of the resulting pressurized liquid is obtained by performing at least one of the following steps: before, during, or after the process of liquefying the boil-off stream, removing from the boil-off stream a predetermined amount of one or more components, such as nitrogen, having a vapor pressure greater than the vapor pressure of methane, and before, during, or after the process of liquefying the boil-off stream, adding to the boil-off stream one or more additives having a molecular weight heavier than the molecular weight of methane and having a vapor pressure less than the vapor pressure of methane.

[0025] U.S. Pat. No. 7,127,914, issued Oct. 31, 2006, to Roberts et al., discloses a method for gas liquefaction comprising cooling a feed gas by a first refrigeration system in a first heat exchange zone and withdrawing a substantially liquefied stream therefrom, further cooling the substantially liquefied stream by indirect heat exchange with one or more work-expanded refrigerant streams in a second heat exchange zone, and withdrawing therefrom a further cooled, substantially liquefied stream. At least one of the one or more work-expanded refrigerant streams is provided by compressing one or more refrigerant gases to provide a compressed refrigerant stream, cooling all or a portion of the compressed refrigerant stream in a third heat exchange zone to provide a cooled, compressed refrigerant stream, and work expanding the cooled, compressed refrigerant stream to provide one of the one or more work-expanded refrigerant streams. The flow rate of a work-expanded refrigerant stream in the second heat exchange zone typically is less than the total flow rate of one or more work-expanded refrigerant streams in the third heat exchange zone.

[0026] U.S. Pat. No. 7,204,100, issued Apr. 17, 2007, to Wilkinson et al., discloses a process for liquefying natural gas in conjunction with producing a liquid stream containing predominantly hydrocarbons heavier than methane. In the process, the natural gas stream to be liquefied is partially cooled and divided into first and second streams. The first stream is further cooled to condense substantially all of it, expanded to an intermediate pressure, and then supplied to a distillation column at a first mid-column feed position. The second stream is also expanded to intermediate pressure and is then supplied to the column at a second lower mid-column feed position. A distillation stream is withdrawn from the column below the feed point of the second stream and is cooled to condense at least a part of it, forming a reflux stream. At least a portion of the reflux stream is directed to the distillation column as its top feed. The bottom product from this distillation column preferentially contains the majority of any hydrocarbons heavier than methane that would otherwise reduce the purity of the liquefied natural gas. The residual gas stream from the distillation column is compressed to a higher intermediate pressure, cooled under pressure to condense it, and then expanded to low pressure to form the liquefied natural gas stream.

[0027] U.S. Pat. No. 7,225,636, issued Jun. 5, 2007, to Baudat, discloses an apparatus for and process for recovering LNG from reservoir natural gas which includes circulating a portion of the natural gas thru a gas cooling loop that includes heat exchanges, an expansion zone and compression zone. The process also includes removing liquids from the gas cooling loop, distilling those liquids to recover a distilled gas. The process also includes compressing and expanding various portions of the distilled gas and passing those portions thru heat exchangers shared with the gas cooling loop to effect heating/cooling as desired. The process also includes removing a portion of the LNG cooling loop as LNG product.

[0028] U.S. Pat. No. 7,310,971, issued Dec. 25, 2007, to Eaton, discloses an improved apparatus and method for providing reflux to a refluxed heavies removal column of a LNG facility. The apparatus comprises stacked vertical core-in-kettle heat exchangers and an economizer disposed between the heat exchangers. The reflux stream originates from the methane-rich refrigerant of the methane refrigeration cycle. The liquid reflux stream generated by cooling the methane-rich stream in the vertical heat exchangers via indirect heat exchange with an upstream refrigerant.

[0029] U.S. Patent Publication No 20060260358, published Nov. 23, 2006, to Eaton, discloses single or double column cryogenic gas-separation/liquefaction devices, where refrigeration to the device is supplied by a cryocooler alone or by a combination of a cryocooler and by a Joule-Thompson throttling process, where the gas condensation may occur directly on the cold portion of the cryocooler which may be located inside of the thermally insulated space of the distillation column(s). The invention principles include a combined column embodiment for simultaneous production of high-purity liquid or gaseous oxygen and nitrogen. Another double column design offers reduced temperature and pressure separation with easy switching between oxygen and nitrogen extraction or single component extraction. If both gaseous and liquid oxygen are required, oxygen purity of approximately 95% can be produced with good recovery, i.e., with nitrogen purity of approximately 91%.

[0030] All of the patents cited in this specification, are herein incorporated by reference.

[0031] However, in spite of the above advancements, there still exists a need in the art for apparatus and methods for processing and liquefying natural gas.

[0032] This and other needs in the art will become apparent to those of skill in the art upon review of this specification, including its drawings and claims.

SUMMARY OF THE INVENTION

[0033] It is an object of the present invention to provide for improved apparatus and methods for processing natural gas.

[0034] This and other objects of the present invention will become apparent to those of skill in the art upon review of this specification, including its drawings and claims.

[0035] According to one embodiment of the present invention there is provided a method for cooling natural gas with a refrigerant. The method may include one or more of the following, in any order. The method may include compressing and cooling the refrigerant to a first pressure to form a compressed refrigerant. The method may also include splitting the compressed refrigerant into a first stream and a second stream both at the first pressure. The method may even also include cooling the first stream to form a cooled first stream. The method may still also include expanding the cooled first stream to a first expansion pressure to form an expanded first stream. The method may yet also include compressing the second stream to a second pressure higher than the first pressure, forming a higher pressure second stream. The method may even still include cooling the higher pressure second stream to form a cooled second stream. The method may even yet include expanding the cooled second stream to a second expansion pressure to form an expanded second stream. The method may still even include cooling the natural gas with the expanded first stream and expanded second stream, forming a cooled natural gas stream. Various sub-embodiments of this embodiment may include any one or more of the following in any order: wherein the natural gas is first pretreated to remove at least one selected from the group consisting of non-hydrocarbon impurities, nitrogen, carbon dioxide, hydrogen sulfide, carbonyl sulfide, mercaptans water, and helium; wherein the natural gas is first pretreated to reduce the quantity of C6+ hydrocarbon components; wherein the refrigerant is split into a third or more streams; wherein at least one of the first expansion pressure or the second expansion pressure is less than 1.18 MPa; wherein the natural gas is split into multiple portions, each portion cooled in parallel with the other portions; wherein a portion of the cooled natural gas stream is used to pretreat the natural gas; and wherein there is formed a heated first stream, a heated second stream, the method further comprising combining, compressing and cooling the heated first stream and the heated second stream to form the refrigerant for use in the start of the method.

[0036] According to another embodiment of the present invention there is provided a method for cooling natural gas with a refrigerant. The method may include one or more of the following, in any order. The method may include compressing and cooling the refrigerant to a first pressure to form a compressed refrigerant. The method may also include splitting the refrigerant into a first stream and a second stream both at the first pressure. The method may also include cooling the first stream to form a cooled first stream. The method may also include expanding the cooled first stream to a first expansion pressure to form an expanded first stream. The method may also include compressing second stream to a second pressure higher than the first pressure forming a higher pressure second stream. The method may also include cooling the higher pressure second stream to form a cooled second stream. The method may also include expanding the cooled second stream to form an expanded second stream at a second expansion pressure. The method may also include cooling the natural gas in at least one aluminum plate heat exchanger with the expanded first stream and the expanded second stream to form a cooled natural gas stream, wherein the natural gas is at a pressure of at least 5.5 MPa. Various sub-embodiments of this embodiment may include any one or more of the following in any order: wherein the pressure is at least 6 MPa, wherein the natural gas is first pretreated to remove at least one selected from the group consisting of non-hydrocarbon impurities, nitrogen, carbon dioxide, hydrogen sulfide, carbonyl sulfide, mercaptans water, and helium; wherein the natural gas is first pretreated to reduce the quantity of C6+ hydrocarbon components; wherein the refrigerant is split into at least the first stream, the second stream and a third stream; wherein at least one of the first expansion pressure or the second expansion pressure is less than 1.15 MPa, wherein the aluminum plate heat exchanger comprises multiple cores operating in parallel and the natural gas is split into multiple portions, each portion cooled in one of the cores; wherein a portion of the cooled natural gas stream is used to pretreat the natural gas; wherein there is formed a heated first stream, a heated second stream, the method further comprising combining, compressing and cooling the heated first stream and the heated second stream to form the refrigerant for use at the start of the method.

[0037] According to even another embodiment of the present invention there is provided a method for cooling natural gas with a refrigerant. The method may include one or more of the following, in any order. The method may include compressing and cooling the refrigerant to a first pressure to form a compressed refrigerant. The method may include splitting the refrigerant into a first stream and a second stream both at the first pressure. The method may include cooling the first stream to form a cooled first stream. The method may include expanding the cooled first stream to form an expanded first stream at a first expansion pressure. The method may include compressing second stream to a second pressure higher than the first pressure forming a higher pressure second stream. The method may include cooling the higher pressure second stream to form a cooled second stream. The method may include expanding the cooled second stream to the expansion pressure to form a expanded second stream. The method may include cooling the natural gas with the cooled first stream and the cooled second stream to form a cooled natural gas stream, wherein the natural gas is at a pressure less than 5.5 MPa, wherein the cooling is carried out in at least one heat exchanger selected from the group comprising a spiral wound heat exchanger, a printed circuit heat exchanger and a spool wound heat exchanger. Various sub-embodiments of this embodiment may include any one or more of the following in any order: wherein the natural gas pressure is less than 5 MPa; and wherein in the natural gas pressure is less than 4.5 MPa.

[0038] According to still another embodiment of the present invention there is provided a method for cooling natural gas with a refrigerant. The method may include one or more of the following, in any order. The method may include compressing and cooling the refrigerant to a first pressure to form a compressed refrigerant. The method may include splitting the compressed refrigerant into a first stream and a second stream both at the first pressure. The method may include cooling the first stream to form a cooled first stream. The method may include expanding the cooled first stream to a first expansion pressure to form an expanded first stream. The method may include compressing the second stream to a second pressure higher than the first pressure, forming a higher pressure second stream. The method may include cooling the higher pressure second stream to form a cooled second stream. The method may include expanding the cooled second stream to a second expansion pressure to form an expanded second stream. The method may include cooling the natural gas with the expanded first stream and the expanded second stream forming a heated second stream. In the method at least one of the first expansion pressure and the second expansion pressure are less than 1.18 MPa. Various sub-embodiments of this embodiment may include any one or more of the following in any order: wherein at least one of the first expansion pressure or the second expansion pressure is less than 1.17 MPa; and wherein at least one of the first expansion pressure or the second expansion pressure is less than 1.16 MPa.

[0039] According to yet another embodiment of the present invention there is provided a method for processing natural gas. The method may include one or more of the following, in any order. The method may include providing a first natural gas vapor stream to a fractionation tower. The method may include providing a second natural gas stream to the fractionation tower as a reflux stream. The method may include separating the first natural gas vapor stream into a heavy component liquid stream and a light component vapor stream.

[0040] According to even still another embodiment of the present invention, there is provided apparatus comprising part or all of the apparatus disclosed to carry out any method or method step disclosed herein.

BRIEF DESCRIPTION OF THE DRAWINGS

[0041] The following drawings illustrate some of the many possible embodiments of this disclosure in order to provide a basic understanding of this disclosure. These drawings do not provide an extensive overview of all embodiments of this disclosure. These drawings are not intended to identify key or critical elements of the disclosure or to delineate or otherwise limit the scope of the claims. The following drawings merely present some concepts of the disclosure in a general form. Thus, for a detailed understanding of this disclosure, reference should be made to the following detailed description, taken in conjunction with the accompanying drawings, in which like elements have been given like numerals.

[0042] FIG. **1** is a schematic representation of one non-limiting embodiment **100** of a gas pretreatment process.

[0043] FIG. **2** is a schematic representation of one non-limiting embodiment **200** for processing natural gas into liquefied natural gas ("LNG").

[0044] FIG. **3** is a schematic representation of one non-limiting embodiment **300** for processing natural gas into liquefied natural gas ("LNG").

[0045] FIG. **4** is an isometric front view of brazed aluminum heat exchanger **240**.

[0046] FIG. **5** is an isometric back view of brazed aluminum heat exchanger **240**.

[0047] FIG. **6** is a front view of brazed aluminum heat exchanger (BAHX) **240**.

[0048] FIG. **7** is side views of brazed aluminum heat exchanger (BAHX) **240**.

DETAILED DESCRIPTION OF THE INVENTION

[0049] The present invention will find utility with a wide variety of natural gas sources, and in a wide variety of environments/locations. As a non-limiting example the present invention is believed to have application both onshore and offshore. Some embodiments of the present invention may be particularly useful in the processing of gas fields or associated gas from geographically remote or offshore locations for which pipelines are not present or are cost prohibitive to install.

[0050] It should be understood that the proposed design operating conditions (i.e., temperature, pressure, compositions, flowrates, sizing, etc.) for the various process streams shown in FIGS. **1** and **2** can vary depending upon the composition of the input feed gas being processed, equipment design variations, process design variations, climactic factors, and the particular manner in which the equipment and process are being operated. In addition, conditions may also vary depending upon particular operating goals/limitations, which force/require that any plant be operated in a certain manner. Flowrates, of course, vary depending upon plant capacity and size. It should also be noted that any temperatures, pressures, flowrates, heating/cooling duties, and the like, shown in FIGS. **1** and **2** and/or discussed herein, should be considered merely design examples and may vary depending upon any number of design/operational circumstances. It is to be understood that values inside or outside those ranges could be utilized, given particular circumstances.

[0051] It should be understood that the various physical components of the present invention may be any that are well known to those of skill in the art. The patentability of the apparatus of the present invention does not reside in the patentablity of any single piece of equipment, but rather in the unique and nonobvious arrangement of the various pieces of equipment to form the overall apparatus or portion of the apparatus. Likewise, individual process steps are generally known to those of skill in the art. The patentability of the process of the present invention does not reside in the patentablity of any single process step, but rather in the unique and nonobvious arrangement of the various process steps to form the overall process or a portion of the process.

[0052] The terms "gas" (or "vapor") and "liquid" are used throughout this document as is common in the industry. It should be noted that streams which are above their critical pressure actually exist in a single dense phase.

[0053] The present invention will now be discussed by reference to FIG. **1**, which is a schematic representation of one non-limiting embodiment of a gas pretreatment process.

[0054] Natural gas stream **101** comprises raw untreated natural gas. As used throughout the specification, natural gas is understood to mean raw natural gas or treated natural gas. Raw natural gas primarily comprises light hydrocarbons such as methane, ethane, propane, butanes, pentanes, hexane and potentially other hydrocarbons, but may also comprise small amounts of non-hydrocarbon impurities, such as nitrogen, carbon dioxide, hydrogen sulfide, carbonyl sulfide, various mercaptans or water, and/or traces of helium. Treated natural gas primarily comprises methane, ethane, and propane but may also comprise nitrogen and a small percentage of heavier hydrocarbons such as butanes and pentanes.

[0055] As non-limiting examples, natural gas may comprise as little as 55 mole percent methane. However, it is preferable that the natural gas suitable for this process comprises at least about 75 mole percent methane, more preferably at least about 85 mole percent methane, and most preferably at least about 90 mole percent methane for best results. Likewise, the exact composition of the non-hydrocarbon impurities also varies depending upon the source of the natural gas.

[0056] Consequently, it is often necessary to pretreat the natural gas in one or more pretreatment processes **10** to reduce the concentrations of non-hydrocarbon impurities such as acid gases, mercury, and water that can freeze, plug lines and heat exchangers, or otherwise damage equipment used in the process.

[0057] A common optional pretreatment **10** for gas stream **101** includes passing it through an amine absorber to remove carbon dioxide. In addition to being corrosive, carbon dioxide will solidify at cryogenic temperatures and cause operational problems in the cryogenic liquefaction process. Stream **102** represents carbon dioxide removed in pretreatment step **10**.

[0058] Another common pretreatment **10** for gas stream **101** includes dehydration to remove water that solidifies at cryogenic temperatures. Stream **103** represents water removed in pretreatment step **10**.

[0059] Another common pretreatment **10** for gas stream **101** includes passing it through a mercury guard bed, as mercury is corrosive to the aluminum equipment commonly used in cryogenic operations. Even if mercury is not detectable in the gas stream analysis, it is generally preferred to guard against its presence.

[0060] Of course, impurities will vary from gas source to gas source, and any other pretreatments as dictated by the impurities of the particular gas source may be utilized.

[0061] In the embodiment as shown in FIG. **1**, natural gas stream **115** is a treated gas stream, that is, it has been treated to remove certain impurities as discussed above.

[0062] In some instances, it may be necessary to further pretreat this natural gas to reduce the quantity of heavy hydrocarbon components (typically hexane and heavier components, referred to as C6+) in the gas, as these components may be disruptive in the liquefaction process. Natural gas stream **115** from pretreatment **10** is mostly methane, with a few percent ethane and propane, a fraction butanes, and some lesser amount of pentanes and C6+ components. In the non-limiting embodiment as shown, a scrubber tower **12** is utilized to remove most of the C6+ components from the gas. In some embodiments, the resulting natural gas stream **127** exiting the overhead of the scrubber tower may contain no more than 5 ppm by weight of C6+ components.

[0063] Natural gas stream **115** provided from pretreatment **10** may be optionally split into primary stream **117** and a smaller gas stream **118**. This split may be manually controlled, or may be subject to automatic control based on conditions of the process. Gas stream **118** is introduced into the lower end of scrubber tower **12** to provide vapor flow in the bottom section of the tower. Stream **118** may supplement or replace vapor that would otherwise be produced in a conventional reboiler.

[0064] In a non-limiting embodiment as shown, a feed/product exchanger **11** is utilized to cool the primary feed gas stream **117** and to warm the cold scrubber overhead product stream **127**. Natural gas stream **117** is cooled by exchanger **11** becoming cooled natural gas stream **105**, and is then introduced into the mid section of scrubber **12**. The use of exchanger **11** reduces the cooling duty that would otherwise be required at tower **12**. In a further optional embodiment, feed/product exchanger **11** may be provided with any suitable supplemental cooling not shown, whether a separate or dedicated refrigerant stream or a recycle stream.

[0065] In the non-limiting embodiment as shown, reflux for scrubber tower **12** may be generated utilizing substantially cooled natural gas or LNG from one or more sources (as a non-limiting example, stream **109** of FIG. **2**), and bottom vapor is provided by gas stream **118**. This configuration of this embodiment is relatively simple yet effective and utilizes a small number of equipment items and minimal process control. This simplicity is considered an advantage for this configuration. Certainly the overhead cooling duty and bottom heating duty may be provided by a wide variety of means and methods, including a traditional overhead condenser (potentially utilizing a refrigerant for cooling) and reboiler. Optionally, the scrubber tower can be operated as a refluxed absorber, a reboiled absorber, or even as a simple flash vessel.

[0066] The preferred operating pressure of the scrubber tower is lower than the pressure of the feed gas to liquefaction, stream **110**. In one non-limiting embodiment the scrubber tower operates between 300 and 650 psig. While in some embodiments the scrubber tower may be operated at pressures above or below this range, the advantage of operating the scrubber tower in this pressure range rather than a higher pressure is that the separation efficiencies of the heavy components are improved at the lower operating pressure. At lower operating pressures, equipment and piping will be larger, increasing space requirements and capital costs.

[0067] In a further optional embodiment, feed/product exchanger **11** may also be utilized to pre-cool natural gas in pretreatment **10** upstream of dehydration to condense water and thus reduce the duty on the dehydration equipment. As shown, a natural gas pretreatment stream **111** is cooled in exchanger **11** exiting as a cooled stream **112**. At knock out vessel **13** this stream **112** may be separated, depending upon its composition, into water stream **113** and liquid hydrocarbon stream **114**, with a gas stream **116** returning to pretreatment **10**.

[0068] Scrubber bottoms stream **119** contains the separated C6+ components along with some pentanes, butanes, and lighter components and may be used as fuel or treated further and/or sent to storage depending upon the needs of the facility.

[0069] Scrubber overhead stream **127** is void of most C6+ components and is quite cold. To provide cooling to the scrubber tower feed gas, overhead stream **127** is routed through exchanger **11** exiting as a warmer gas stream **128**. This gas stream **128** may optionally be routed to booster compression equipment **15** to produce a gas stream **110** of suitable pressure for feeding to the liquefaction process. This pressure may be at, above or below the critical pressure of the gas stream. In some embodiments the booster compressors will provide a gas stream **110** with a pressure of about 800 psig.

[0070] As an option to the scrubber tower **12** upstream of liquefaction process **200**, any suitable optional process for removal of NGL (ethane and heavier components) or LPG (propane and heavier components) may be utilized.

[0071] Referring additionally to FIG. **2**, there is shown a schematic representation of one non-limiting embodiment **200** for processing natural gas into liquefied natural gas ("LNG").

[0072] Natural gas feed stream **110** may have been optionally treated to remove C6+ components in a process such as that of FIG. **1**. This natural gas feed stream **110** may have transited through compression equipment to arrive at a certain desired pressure for processing. In a non-limiting embodiment that processing pressure may be on the order of 800 psig, although it should be understood that pressures up to 1100 psig, 1200 psig, or perhaps even higher, or as low as 600 psig, 500 psig or even lower may be used. In some non-limiting embodiments, in which main heat exchanger **240** comprises an aluminum or brazed aluminum plate heat exchanger the pressure of stream **110** may be at least 5.5 MPa, greater than 5.5 MPa, greater than 6 MPa, greater than 6.5 MPa, greater than 7 MPa, greater than 7.5 MPa, and greater than 8 MPa. In some non-limiting embodiments, in which main heat exchanger **240** comprises a printed circuit heat exchanger (PCHE), spiral wound heat exchanger or spool wound heat exchanger the pressure of stream **110** may be 5.5 MPa or less, less than 5.5 MPa, less than 5 MPa, less than 4.5 MPa, and less than 4 MPa.

[0073] Stream **110** then passes through main heat exchanger **240** where it is significantly cooled, exiting as stream **211** at a temperature on the order of −235 to −250 F. The temperature of stream **211** is low enough that the stream becomes substantially liquefied when later flashed (or expanded) to a pressure below its critical pressure. Stream **211** may be split into stream **109** that is used to provide reflux to scrubber tower **12** of FIG. **1**, and stream **203** which is released through a valve **241** to low pressure (near atmospheric) stream **212** and sent to LNG storage or flash vessel **236**. Valve **241** may be optionally replaced with or supplemented by an expander. A small amount of flash gas is formed when stream **203** drops in pressure and temperature across valve (or expander) **241**. The combined flash gas and any boil-off gas generated by heat in-leak to the LNG storage or flash vessel **236** produces a cold, low-pressure gas stream **212**. In the embodiment shown, stream **212** is boosted in pressure by blower **237** and the resulting stream **238** is returned to the main heat exchanger **240** in order to recover its cooling duty. Stream **238** (predominantly methane, nitrogen, and some ethane) exits the main heat exchanger **240** as a significantly warmer gas stream **239**. In a typical embodiment, stream **239** may be compressed for use as fuel gas to gas turbines used as process drivers or for power generation. Any gas from stream **239** that exceeds the amount needed for fuel gas may be optionally recycled to the process upstream of the liquefaction equipment. By varying the temperature of stream **211**, more or less flash gas may be produced. Optionally, the temperature of stream **211** may be controlled such that stream **239** produces nearly or exactly the quantity of fuel gas required by the facility. In another embodiment, flash vessel **236** may be replaced with a nitrogen scrubber tower to significantly reduce the nitrogen content of the LNG product.

[0074] In the non-limiting embodiment as shown, cooling is provided to main heat exchanger **240** by two joined refrigeration loops. Certainly, any number of loops including at least 2, 3, 4, 5, 6, 7, 8, 9, 10, or more, may be utilized, and any suitable refrigerant may be utilized. Non-limiting examples of suitable refrigerants include nitrogen, air, argon, hydrocarbons, helium, suitable cryogenic refrigerants, and mixtures of two or more thereof. A preferred refrigerant comprises nitrogen and oxygen; a non-limiting example includes nitrogen containing 0 to 21% oxygen by volume. In the preferred embodiment, the refrigerant may remain in the gaseous phase at all points in the process. This is an advantage particularly for offshore applications in which the process equipment is subject to tilt, roll, or other vessel motions, since no distribution of a mixed-phase refrigerant is required. Some embodiments of the present invention may utilize non-flammable refrigerants. Optionally, in some embodiments, closed-loop refrigeration may be added, either in combination with the heat exchangers described here or in separate heat exchangers, to cool the gas entering the liquefaction process or to cool the refrigerant gas exiting the refrigerant compressors. The use of separate closed-loop refrigerant may improve the energy efficiency of the overall process. The refrigerant stream may be split into two loops at piping split S and combined back together at piping junction J.

[0075] Starting at piping junction J, the refrigerant stream **213** at approximately ambient temperature (depending on the temperature of the process cooling media, for example air, water, or chilled water) undergoes a number of stages of compression with cooling following each stage of compression.

[0076] In the example shown, refrigerant stream **213** is compressed (and heated) by compressor **243** and exits as stream **214**. Subsequent cooling of stream **214** is provided by cooler **244** resulting in a cooled stream **215**. In the example shown, compressor **243** is driven by expander **242**.

[0077] Refrigerant stream **215** is compressed (and heated) by a compressor stage **245** and exits as stream **216**. Subsequent cooling of stream **216** is provided by cooler **246** resulting in a cooled stream **217**. Stream **217** is compressed (and heated) by compressor stage **247** and exits as stream **218**. Subsequent cooling of stream **218** is provided by cooler **249** resulting in a cooled stream **219**. In one non-limiting embodiment, the pressure of stream **219** is about 670 psig. In some non-limiting embodiments compressor stages **245** and **247** are typically driven by a single driver, examples of which may include an electric motor, a gas turbine, aeroderivative gas turbine, or a steam turbine.

[0078] Cooled refrigerant stream **219** is then split into two loops at piping split S: a lower pressure, warmer loop beginning with stream **220**, and a higher pressure, cooler loop beginning with stream **230**. In the practice of the present invention, the higher pressure lower temperature refrigerant loop is further compressed to a pressure substantially higher than that of stream **220**.

[0079] Cooling may be provided to coolers **244**, **246**, **249**, and **252** by any suitable means and method, and by using any suitable cooling medium. There may be one or more cooling systems that service these coolers. In one non-limiting embodiment, cooling water is provided to each of those coolers.

[0080] With reference now to the lower pressure warmer loop, stream **220** is cooled in main heat exchanger **240**, exiting as stream **221**. Expansion of stream **221** through expander **242** provides a cooler stream **222**. This stream **222** provides cooling to main heat exchanger **240**, exiting as stream **223**. The temperatures of stream **221** and **222** will vary depending on many factors including but not limited to the composition of the gas being liquefied and the efficiency of expander **242**. A typical temperature range for stream **221** is −5 to 30 F and a typical temperature range for stream **222** is between −145 and −120 F. Similarly, the pressure of stream **222** may vary. In one non-limiting embodiment, the pressure of stream **222** is about 150 psig.

[0081] With reference now to the higher pressure cooler loop, stream **230** is now further compressed by compressor **251** forming compressed stream **231**, which is then subsequently cooled by cooler **52**, exiting as cooled stream **232**. In the example shown, compressor **251** is driven by expander **250**. Stream **232** is cooled in main heat exchanger **240**, exiting as stream **233**. Expansion of stream **233** through expander **250** provides a cooler stream **234**. This stream **234** provides cooling to main heat exchanger **240**, exiting as stream **235**. The advantage of the additional compression step **251** is that stream **232** does not need to be cooled in exchanger **240** to as low a temperature at stream **233** in order to achieve the required expander outlet temperature for stream **234**. By comparison, without compression step **251**, the pressure drop (and corresponding temperature drop) would have been much less across expander **250**, meaning that the temperature of stream **233** would need to be substantially lower to achieve the required temperature of expanded stream **234**. The temperatures of stream **233** and **234** will vary depending on many factors including but not limited to the composition of the gas being liquefied and the efficiency of expander **250**. In some non-limiting embodiments, a typical temperature range for stream **233** is −80 to −110 F and a typical temperature range for stream **234** is between −235 and −265 F. Similarly, the pressure of stream **234** may vary. In one non-limiting embodiment, the pressure of stream **234** is about 150 psig.

[0082] The pressure of stream **232** entering main heat exchanger may be any suitable desired pressure. In some non-limiting embodiments, in which main heat exchanger **240** comprises an aluminum or brazed aluminum plate heat exchanger the pressure of stream **232** may be at least 5.5 MPa, greater than 5.5 MPa, greater than 6 MPa, greater than 6.5 MPa, greater than 7 MPa, greater than 7.5 MPa, and greater than 8 MPa. In some non-limiting embodiments, in which main heat exchanger **240** comprises a printed circuit heat exchanger (PCHE) the pressure of stream **232** may be 5.5 MPa or less, less than 5.5 MPa, less than 5 MPa, less 4.5 MPa, and less than 4 MPa.

[0083] After being warmed in main heat exchanger **240**, lower pressure warmer loop stream **223** and higher pressure cooler loop **235** are combined together at piping junction J. It should be understood that streams **222** and **234** should be expanded to approximately the same expansion pressure so that streams **223** and **235** can be joined without additional controls and/or processing. By approximately the same expansion pressure it is meant within 0.05 MPa, 0.1 MPa, 0.15 MPa, 0.2 MPa, or 0.25 Mpa. Certainly the closer the expansion pressures the more readily the streams may be joined without having to adjust for pressure differences. In some embodiments, the expansion pressures will be less than 1.18 MPa, less the 1.17 MPa, less than 1.16 MPa, less the 1.15 MPa, less than 1.14 MPa, less the 1.13 MPa, less than 1.12 MPa, less the 1.11 MPa, and less than 1.10 MPa. Refrigerant makeup **224** may be provided as necessary to maintain the overall refrigerant inventory.

[0084] In the practice of the present invention, any suitable heat exchanger may be utilized for main heat exchanger **240**. One non-limiting example of a suitable heat exchanger includes an aluminum plate heat exchanger (also known as an aluminum plate fin heat exchanger or brazed aluminum heat exchanger) **240** as shown in FIGS. **4-7**. An non-limiting example of a suitable aluminum plate heat exchanger includes those discloses in U.S. Pat. Application entitled *Brazed Aluminum Heat Exchanger With Split Core Arrangement,* filed on even date herewith by David A. Franklin et al., which application is hereby incorporated by reference.

[0085] FIGS. **4** and **5** are isometric front and back views of brazed aluminum heat exchanger **240**. FIGS. **6** and **7** are front and side views of brazed aluminum heat exchanger (BAHX) **240**. The piping numbers correspond to stream numbers in FIG. **2**. In the non-limiting embodiment as shown, the various streams enter and exit through the center of heat exchanger **240**, with BAHX cores **281** and **283** on one side, and BAHX cores **282** and **284** on the other side. Various manifolds for each incoming and outgoing stream are connected to each of the cores. Specifically, each of pipes **110**, **239**, **232**, **220**, **221**, **232**, **233**, **234**, **211**, **238** and **222**, have corresponding manifolds **110**M, **239**M, **232**M, **220**M, **221**M, **232**M, **233**M, **234**M, **211**M, **238**M and **222**M, respectively as shown. Exit piping **213** receives flow from internal piping **235** and **223**. Both piping **235** and **223** have respective manifolds **235**M and **223**M.

[0086] In some embodiments, if gas stream **110** is at substantially lower temperature than shown in the above example, the relative flow rates, temperature, and/or pressure of the lower pressure and the higher pressure refrigerant loops may change from what is described in the example.

EXAMPLES

[0087] The following tables show computer modeling results for one example of the process of the present invention as shown in FIG. **1** and FIG. **2**.

	Stream Number				
	101	102	103	105	109
Vapour Fraction	1.000	1.000	0.000	0.996	0.000
Temperature [C]	37.8	37.8	15.0	−45.6	−150.8
Pressure [bar]	35.5	35.5	31.4	33.1	55.8
Molar Flow [MMSCFD]	83.8	0.7	0.0	78.8	1.5
Mass Flow [kg/h]	74813	1537	41	69465	1318
Molecular Weight	17.9	44.0	18.0	17.7	17.6
Mole Frac Nitrogen	0.00959	0.00000	0.00000	0.00969	0.00971
Mole Frac O2	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac CO2	0.00837	1.00000	0.00000	0.00000	0.00000
Mole Frac H2O	0.00206	0.00000	1.00000	0.00000	0.00000
Mole Frac Methane	0.89367	0.00000	0.00000	0.90310	0.90428
Mole Frac Ethane	0.07067	0.00000	0.00000	0.07141	0.07137
Mole Frac Propane	0.01010	0.00000	0.00000	0.01020	0.01009
Mole Frac i-Butane	0.00406	0.00000	0.00000	0.00410	0.00379
Mole Frac n-Butane	0.00067	0.00000	0.00000	0.00067	0.00057
Mole Frac i-Pentane	0.00033	0.00000	0.00000	0.00034	0.00015
Mole Frac n-Pentane	0.00016	0.00000	0.00000	0.00016	0.00004
Mole Frac n-Hexane	0.00014	0.00000	0.00000	0.00014	0.00000
Mole Frac n-Heptane +	0.00019	0.00000	0.00000	0.00019	0.00000

	Stream Number				
	110	111	112	113	114
Vapour Fraction	1.000	1.000	0.998	0.000	0.000
Temperature [C]	37.8	37.8	15.0	15.0	15.0
Pressure [bar]	56.2	35.5	35.1	35.1	35.1
Molar Flow [MMSCFD]	84.3	83.1	83.1	0.1	0.0
Mass Flow [kg/h]	74044	73276	73276	114	0
Molecular Weight	17.6	17.7	17.7	18.0	58.0
Mole Frac Nitrogen	0.00971	0.00967	0.00967	0.00000	0.00146
Mole Frac O2	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac CO2	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac H2O	0.00000	0.00208	0.00208	0.99999	0.00056
Mole Frac Methane	0.90428	0.90122	0.90122	0.00000	0.37505
Mole Frac Ethane	0.07137	0.07126	0.07126	0.00000	0.13836
Mole Frac Propane	0.01009	0.01018	0.01018	0.00000	0.06281
Mole Frac i-Butane	0.00379	0.00409	0.00409	0.00000	0.05871
Mole Frac n-Butane	0.00057	0.00067	0.00067	0.00000	0.01308
Mole Frac i-Pentane	0.00015	0.00034	0.00034	0.00000	0.01513
Mole Frac n-Pentane	0.00004	0.00016	0.00016	0.00000	0.00927
Mole Frac n-Hexane	0.00000	0.00014	0.00014	0.00000	0.02373
Mole Frac n-Heptane +	0.00000	0.00019	0.00019	0.00000	0.30183

	Stream Number				
	115	116	117	118	119
Vapour Fraction	1.000	1.000	1.000	1.000	0.000
Temperature [C]	15.0	15.0	15.0	15.0	−2.5
Pressure [bar]	33.4	35.1	33.4	33.4	33.0
Molar Flow [MMSCFD]	82.9	83.0	78.8	4.1	0.1
Mass Flow [kg/h]	73121	73162	69465	3656	395
Molecular Weight	17.7	17.7	17.7	17.7	57.7
Mole Frac Nitrogen	0.00969	0.00969	0.00969	0.00969	0.00060
Mole Frac O2	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac CO2	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac H2O	0.00000	0.00056	0.00000	0.00000	0.00000
Mole Frac Methane	0.90310	0.90259	0.90310	0.90310	0.18665
Mole Frac Ethane	0.07141	0.07137	0.07141	0.07141	0.09287
Mole Frac Propane	0.01020	0.01020	0.01020	0.01020	0.07891
Mole Frac i-Butane	0.00410	0.00410	0.00410	0.00410	0.19092
Mole Frac n-Butane	0.00067	0.00067	0.00067	0.00067	0.06396
Mole Frac i-Pentane	0.00034	0.00034	0.00034	0.00034	0.11333
Mole Frac n-Pentane	0.00016	0.00016	0.00016	0.00016	0.07290
Mole Frac n-Hexane	0.00014	0.00014	0.00014	0.00014	0.08472
Mole Frac n-Heptane +	0.00019	0.00019	0.00019	0.00019	0.11514

	Stream Number				
	127	128	203	210	211
Vapour Fraction	1.000	1.000	0.000	0.000	0.000
Temperature [C]	−48.0	33.5	−150.8	−160.8	−150.8
Pressure [bar]	32.7	32.4	55.8	1.1	55.8
Molar Flow [MMSCFD]	84.3	84.3	82.8	75.7	84.3
Mass Flow [kg/h]	74044	74044	72726	66694	74044
Molecular Weight	17.6	17.6	17.6	17.7	17.6
Mole Frac Nitrogen	0.00971	0.00971	0.00971	0.00293	0.00971
Mole Frac O2	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac CO2	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac H2O	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac Methane	0.90428	0.90428	0.90428	0.90299	0.90428
Mole Frac Ethane	0.07137	0.07137	0.07137	0.07807	0.07137
Mole Frac Propane	0.01009	0.01009	0.01009	0.01104	0.01009
Mole Frac i-Butane	0.00379	0.00379	0.00379	0.00415	0.00379
Mole Frac n-Butane	0.00057	0.00057	0.00057	0.00062	0.00057

-continued

	Stream Number				
	127	128	203	210	211
Mole Frac i-Pentane	0.00015	0.00015	0.00015	0.00016	0.00015
Mole Frac n-Pentane	0.00004	0.00004	0.00004	0.00004	0.00004
Mole Frac n-Hexane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Heptane +	0.00000	0.00000	0.00000	0.00000	0.00000

	Stream Number				
	212	213	214	215	216
Vapour Fraction	1.000	1.000	1.000	1.000	1.000
Temperature [C]	−160.8	35.0	84.3	37.8	99.1
Pressure [bar]	1.1	10.8	16.2	15.7	26.8
Molar Flow [MMSCFD]	7.1	523.5	523.5	523.5	523.5
Mass Flow [kg/h]	6032	735607	735607	735607	735607
Molecular Weight	17.0	28.2	28.2	28.2	28.2
Mole Frac Nitrogen	0.08180	0.95000	0.95000	0.95000	0.95000
Mole Frac O2	0.00000	0.05000	0.05000	0.05000	0.05000
Mole Frac CO2	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac H2O	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac Methane	0.91805	0.00000	0.00000	0.00000	0.00000
Mole Frac Ethane	0.00015	0.00000	0.00000	0.00000	0.00000
Mole Frac Propane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac i-Butane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Butane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac i-Pentane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Pentane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Hexane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Heptane +	0.00000	0.00000	0.00000	0.00000	0.00000

	Stream Number				
	217	218	219	220	221
Vapour Fraction	1.000	1.000	1.000	1.000	1.000
Temperature [C]	37.8	106.5	37.8	37.8	−7.8
Pressure [bar]	26.3	47.6	47.1	47.1	46.6
Molar Flow [MMSCFD]	523.5	523.5	523.5	360.5	360.5
Mass Flow [kg/h]	735607	735607	735607	506564	506564
Molecular Weight	28.2	28.2	28.2	28.2	28.2
Mole Frac Nitrogen	0.95000	0.95000	0.95000	0.95000	0.95000
Mole Frac O2	0.05000	0.05000	0.05000	0.05000	0.05000
Mole Frac CO2	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac H2O	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac Methane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac Ethane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac Propane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac i-Butane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Butane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac i-Pentane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Pentane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Hexane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Heptane +	0.00000	0.00000	0.00000	0.00000	0.00000

	Stream Number				
	222	223	230	231	232
Vapour Fraction	1.000	1.000	1.000	1.000	1.000
Temperature [C]	−88.8	35.0	37.8	97.9	37.8

-continued

	Stream Number				
	222	223	230	231	232
Pressure [bar]	11.4	10.8	47.1	76.7	76.2
Molar Flow [MMSCFD]	360.5	360.5	163.0	163.0	163.0
Mass Flow [kg/h]	506564	506564	229044	229044	229044
Molecular Weight	28.2	28.2	28.2	28.2	28.2
Mole Frac Nitrogen	0.95000	0.95000	0.95000	0.95000	0.95000
Mole Frac O2	0.05000	0.05000	0.05000	0.05000	0.05000
Mole Frac CO2	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac H2O	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac Methane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac Ethane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac Propane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac i-Butane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Butane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac i-Pentane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Pentane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Hexane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Heptane +	0.00000	0.00000	0.00000	0.00000	0.00000

	Stream Number				
	233	234	235	238	239
Vapour Fraction	1.000	1.000	1.000	1.000	1.000
Temperature [C]	−69.4	−153.6	35.0	−134.0	35.0
Pressure [bar]	75.7	11.4	10.8	2.0	1.8
Molar Flow [MMSCFD]	163.0	163.0	163.0	7.1	7.1
Mass Flow [kg/h]	229044	229044	229044	6032	6032
Molecular Weight	28.2	28.2	28.2	17.0	17.0
Mole Frac Nitrogen	0.95000	0.95000	0.95000	0.08180	0.08180
Mole Frac O2	0.05000	0.05000	0.05000	0.00000	0.00000
Mole Frac CO2	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac H2O	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac Methane	0.00000	0.00000	0.00000	0.91805	0.91805
Mole Frac Ethane	0.00000	0.00000	0.00000	0.00015	0.00015
Mole Frac Propane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac i-Butane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Butane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac i-Pentane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Pentane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Hexane	0.00000	0.00000	0.00000	0.00000	0.00000
Mole Frac n-Heptane +	0.00000	0.00000	0.00000	0.00000	0.00000

STREAM DESCRIPTIONS	
101	Natural Gas upstream of pretreatment 10
102	CO2 removed in pretreatment 10
103	H2O removed in pretreatment 10
105	Cooled gas feed to scrubber tower 12
109	Substantially cooled natural gas or LNG used to provide reflux to scrubber tower 12
110	Natural Gas stream to liquefaction process
111	Optional gas stream to be cooled prior to dehydration step in pretreatment 10
112	Cooled gas stream to knockout vessel 13
113	Water collected in knockout vessel 13
114	Condensed hydrocarbons (if any; none will form for many feed gas compositions) collected in knockout vessel 13
115	Natural Gas downstream of pretreatment 10
116	Cooled gas from knockout vessel 13 to dehydration step in pretreatment 10
117	Natural Gas from pretreatment 10, after takeoff point for stream 118
118	Natural Gas to bottom of scrubber tower (optional; in place of or in addition to vapor generated by tower reboiler)

-continued

STREAM DESCRIPTIONS	
119	Bottom liquid product from scrubber tower
127	Cold overhead vapor from scrubber tower
128	Warmed overhead vapor from scrubber tower, downstream of feed/product exchanger 11
203	Substantially cooled natural gas downstream of main heat exchanger 240 (upstream of pressure drop, downstream of take-off point for stream 109)
204	Low-pressure LNG/flash gas mixture entering LNG storage or flash vessel 236 (not listed in table; comprised of flash vapor 212 and LNG product 210)
210	LNG product at storage conditions
211	Substantially cooled natural gas downstream of main heat exchanger
212	Combined flash gas and boil-off gas (gas generated due to heat in-leak) from LNG storage or flash vessel 236
213	Combined low pressure, warmed refrigerant gas streams to compressor 243
214	Compressor 243 discharge gas
215	Compressor 243 discharge gas downstream of aftercooler 244
216	Compressor stage 245 discharge gas
217	Compressor stage 245 discharge gas downstream of aftercooler 246
218	Compressor stage 247 discharge gas
219	Compressor stage 247 discharge gas downstream of aftercooler 249
220	Lower pressure warmer loop refrigerant gas from split S to main heat exchanger 240
221	Lower pressure warmer loop refrigerant gas from main heat exchanger 240 to expander 242
222	Lower pressure warmer loop refrigerant gas from expander 242 to main heat exchanger 240
223	Lower pressure warmer loop refrigerant gas from main heat exchanger 240 to combine with higher pressure cooler loop refrigerant gas at junction J
224	Make-up refrigeration gas to closed loop. Normally no flow, not listed in table.
230	Higher pressure cooler loop refrigerant gas from split S to compressor 251
231	Higher pressure cooler loop refrigerant gas discharge from compressor 251
232	Higher pressure cooler loop refrigerant gas discharge from compressor 251, downstream of aftercooler 252, to main heat exchanger 240
233	Higher pressure cooler loop refrigerant gas from main heat exchanger 240 to expander 250
234	Higher pressure cooler loop refrigerant gas from expander 250 to main heat exchanger 240
235	Higher pressure cooler loop refrigerant gas from main heat exchanger 240 to combine with lower pressure warmer loop refrigerant gas at junction J
238	Cold gas from booster blower (or fan) 237 to main heat exchanger 240
239	Warmed gas from main heat exchanger 240. This stream may typically be compressed for use as fuel gas but all or a portion of the stream may be recycled to upstream equipment

Equipment/Block Descriptions

[0088]

10	Pretreatment steps. May include (but is not limited to) removal of CO2, H2S, COS, mercaptans, water, Hg
11	Scrubber Feed/Product Exchanger
12	Scrubber Tower
13	Knockout vessel upstream of dehydration step in pretreatment 10
15	Optional booster compressor and aftercooler for natural gas stream going to liquefaction equipment
236	LNG storage tank or flash vessel
237	Booster blower (or fan) used to slightly raise pressure of combined flash gas/boil off gas stream 212
240	Main liquefaction heat exchanger.
241	Joule-Thomson valve for pressure drop of cold (typically dense phase) LNG from main liquefaction heat exchanger 240 to LNG storage or flash vessel 236. Note that this valve may optionally be replaced by or supplemented by an expander.
242	Expander for lower pressure warmer loop refrigerant gas; drives compressor 243.
243	Compressor for combined refrigerant stream 213 exiting main heat exchanger; driven by expander 242
244	Cooler for discharge gas from compressor 243
245	First stage of main refrigerant compressor
246	Cooler for discharge gas from compressor 245
247	Second stage of main refrigerant compressor
248	Driver for 2 stages of main refrigerant compression 245 and 247
249	Cooler for discharge gas from compressor 247
250	Expander on higher pressure cooler loop refrigerant gas; drives compressor 251
251	Compressor on higher pressure cooler loop refrigerant gas, driven by expander 250
252	Cooler for discharge gas from compressor 247

[0089] Another non-limiting optional embodiment **300** is shown in FIG. **3**. In this embodiment **300**, a scrubber tower for the removal of C6+ components is integrated with the liquefaction process. This may take the place of a scrubber tower upstream of the liquefaction process as shown in FIG. **1**.

[0090] The refrigeration circuit (streams and equipment **109** and **210** thru **252**) are the same as described earlier for FIG. **2**. However the main heat exchanger **240** has been modified with additional streams and is renamed **340**.

[0091] Stream **300** represents pretreated gas for which non-hydrocarbon impurities such as acid gases, mercury, and water have been removed. Stream **300** may optionally be split into a primary stream **300**A and smaller secondary stream **305**. Stream **300**A passes through main heat exchanger **340** where it is cooled to a temperature at which the exiting stream **301** is partially liquefied, but is above the temperature at which C6+ components will start to solidify. In a typical embodiment, stream **301** comprises between 0.05% and 15% liquid. Stream **301** enters a scrubber tower **320**. The liquid product **303** from the scrubber tower **320** is removed and may be used as fuel or processed further and stored.

[0092] Optionally, stream **305** may be introduced into the bottom of scrubber tower **12** to provide vapor flow upward in the lower portion of the tower. Stream **305** may supplement or replace vapor that would otherwise be produced in a conventional reboiler.

[0093] The vapor product **302** from scrubber tower **320** passes through main heat exchanger **340** where it is significantly cooled, exiting as stream **211** at a temperature on the order of −235 to −250 F. Stream **211** may be split into stream **109** that is raised in pressure via pump **310** and used to provide reflux to scrubber tower **320**, and stream **203** which is released through a valve or expander **241** to low pressure (near atmospheric) stream **212** and sent to LNG storage or flash vessel **236**. As another option, reflux for the tower may be generated by cooling and partially condensing all or a portion of the scrubber tower overhead vapor stream, using the liquid of the cooled stream as reflux, and returning the vapor portion to the main heat exchanger for the final cooling pass. This can be performed via a separate heat exchanger or as a further modification to main heat exchanger **340**. The remainder of the streams and equipment shown in FIG. **3** are the same as described earlier for FIG. **2**.

[0094] The present disclosure is to be taken as illustrative rather than as limiting the scope or nature of the claims below. Numerous modifications and variations will become apparent to those skilled in the art after studying the disclosure, including use of equivalent functional and/or structural substitutes for elements described herein, use of equivalent functional couplings for couplings described herein, and/or use of equivalent functional actions for actions described herein. Any insubstantial variations are to be considered within the scope of the claims below.

I claim:

1. A method for cooling natural gas with a refrigerant, the method comprises:

(A) Compressing and cooling the refrigerant to a first pressure to form a compressed refrigerant;

(B) Splitting the compressed refrigerant into a first stream and a second stream both at the first pressure;

(C) Cooling the first stream to form a cooled first stream;

(D) Expanding the cooled first stream to a first expansion pressure to form an expanded first stream;

(E) Compressing the second stream to a second pressure higher than the first pressure, forming a higher pressure second stream;

(F) Cooling the higher pressure second stream to form a cooled second stream;

(G) Expanding the cooled second stream to a second expansion pressure to form an expanded second stream; and,

(H) Cooling the natural gas with the expanded first stream and expanded second stream, forming a cooled natural gas stream.

2. The method of claim **1**, wherein prior to step (H) the natural gas is first pretreated to remove at least one selected from the group consisting of non-hydrocarbon impurities, nitrogen, carbon dioxide, hydrogen sulfide, carbonyl sulfide, mercaptans water, and helium.

3. The method of claim **1**, wherein prior to step (H) the natural gas is first pretreated to reduce the quantity of C6+ hydrocarbon components.

4. The method of claim **1**, wherein in step (B) the refrigerant is split into a third or more streams.

5. The method of claim **1**, wherein at least one of the first expansion pressure or the second expansion pressure is less than 1.18 MPa.

6. The method of claim **1**, wherein the natural gas is split into multiple portions, each portion cooled in parallel with the other portions.

7. The method of claim **1**, wherein a portion of the cooled natural gas stream is used to pretreat the natural gas.

8. The method of claim **1**, wherein in step (H) there is formed a heated first stream, a heated second stream, the method further comprising combining, compressing and cooling the heated first stream and the heated second stream to form the refrigerant for use in step (A).

9. A method for cooling natural gas with a refrigerant, the method comprises:

(A) Compressing and cooling the refrigerant to a first pressure to form a compressed refrigerant;

(B) Splitting the refrigerant into a first stream and a second stream both at the first pressure;

(C) Cooling the first stream to form a cooled first stream;

(D) Expanding the cooled first stream to a first expansion pressure to form an expanded first stream;

(E) Compressing second stream to a second pressure higher than the first pressure forming a higher pressure second stream;

(F) Cooling the higher pressure second stream to form a cooled second stream;

(G) Expanding the cooled second stream to form a expanded second stream at a second expansion pressure; and,

(H) Cooling the natural gas with the expanded first stream and the expanded second stream to form a cooled natural gas stream, wherein the natural gas is at a pressure of at least 5.5 MPa;

wherein at least step (H) is carried out in at least one aluminum plate heat exchanger.

10. The method of claim **9**, wherein in step (H) the pressure is at least 6 MPa.

11. The method of claim **9**, wherein prior to step (H) the natural gas is first pretreated to remove at least one selected from the group consisting of non-hydrocarbon impurities, nitrogen, carbon dioxide, hydrogen sulfide, carbonyl sulfide, mercaptans water, and helium.

12. The method of claim **9**, wherein prior to step (H) the natural gas is first pretreated to reduce the quantity of C6+ hydrocarbon components.

13. The method of claim **9**, wherein in step (B), the refrigerant is split into at least the first stream, the second stream and a third stream.

14. The method of claim **9**, wherein at least one of the first expansion pressure or the second expansion pressure is less than 1.15 MPa.

15. The method of claim **9**, wherein the aluminum plate heat exchanger comprises multiple cores operating in parallel and the natural gas is split into multiple portions, each portion cooled in one of the cores.

16. The method of claim **9**, wherein a portion of the cooled natural gas stream is used to pretreat the natural gas.

17. The method of claim **9**, wherein in step (H) there is formed a heated first stream, a heated second stream, the method further comprising combining, compressing and cooling the heated first stream and the heated second stream to form the refrigerant for use in step (A).

18. A method for cooling natural gas with a refrigerant, the method comprises:

(A) Compressing and cooling the refrigerant to a first pressure to form a compressed refrigerant;

(B) Splitting the refrigerant into a first stream and a second stream both at the first pressure;

(C) Cooling the first stream to form a cooled first stream;

(D) Expanding the cooled first stream to form an expanded first stream at a first expansion pressure;

(F) Compressing second stream to a second pressure higher than the first pressure forming a higher pressure second stream;

(G) Cooling the higher pressure second stream to form a cooled second stream;

(H) Expanding the cooled second stream to the expansion pressure to form a expanded second stream; and,

(H) Cooling the natural gas with the cooled first stream and the cooled second stream to form a cooled natural gas stream, wherein the natural gas is at a pressure less than 5.5 MPa;

wherein, step (H) is carried out in at least one heat exchanger selected from the group comprising a spiral wound heat exchanger, a printed circuit heat exchanger and a spool wound heat exchanger.

19. The method of claim **18**, wherein in step (H) the pressure is less than 5 MPa.

20. The method of claim **18**, wherein in step (H) the pressure is less than 4.5 MPa.

21. A method for cooling natural gas with a refrigerant, the method comprises:

(A) Compressing and cooling the refrigerant to a first pressure to form a compressed refrigerant;

(B) Splitting the compressed refrigerant into a first stream and a second stream both at the first pressure;

(C) Cooling the first stream to form a cooled first stream;

(D) Expanding the cooled first stream to a first expansion pressure to form an expanded first stream;

(E) Compressing the second stream to a second pressure higher than the first pressure, forming a higher pressure second stream;

(F) Cooling the higher pressure second stream to form a cooled second stream;

(G) Expanding the cooled second stream to a second expansion pressure to form an expanded second stream; and,

(H) Cooling the natural gas with the expanded first stream and the expanded second stream forming a heated second stream;

wherein at least one of the first expansion pressure and the second expansion pressure are less than 1.18 MPa.

22. The method of claim **9**, wherein at least one of the first expansion pressure or the second expansion pressure is less than 1.17 MPa.

23. The method of claim **9**, wherein at least one of the first expansion pressure or the second expansion pressure is less than 1.16 MPa.

24. A method for processing natural gas comprising:

(A) Providing a first natural gas vapor stream to a fractionation tower;

(B) Providing a second natural gas stream to the fractionation tower as a reflux stream; and,

(C) Separating the first natural gas vapor stream into a heavy component liquid stream and a light component vapor stream.

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