

- 1 -

TITLE OF THE INVENTION

A SYSTEM AND A PROCESS FOR ENHANCING EFFICIENCY OF CO₂ REMOVAL FROM NATURAL GAS STREAM

FIELD OF THE INVENTION

5 The present invention relates to a system and a process for enhancing efficiency of CO₂ removal from natural gas stream.

BACKGROUND OF THE INVENTION

 In a production of natural gas, removing CO₂ from the natural gas stream to meet specifications before delivering the gas to the pipeline is a common practice since CO₂ is
10 commonly found in natural gas in various locations. A number of systems, processes, methods and techniques for recovery of natural gas or removal of CO₂ have been proposed.

 In a conventional natural gas production, there are two operating plat forms, i.e. a Central Processing Platform (CPP) and a Wellhead platform (WHP). The capacity of the CPP was designed based on flow rate, size of gas reservoirs, CO₂ content in feed natural gas and in
15 methane rich product stream which will be forwarded to Onshore Facilities (OF locating at on-shore location, via sub-sea pipeline or other forms/condition of transport, while the purpose of WHP is primarily to provide the suspension point and pressure seals for casing strings. The current natural gas recovery technology involves a separation unit with pressure and temperature control for removing contaminants including sands, water condensate, and
20 other liquid contaminants installed at CPP. The complexity of this recovery system is that for the sake of CPP's original designs and configuration as well as other certain requirements from Onshore Facilities , the system can only process natural gas with limited range of CO₂ level, i.e. in a range of about 40-50 mole%. Accordingly, this has brought about constraint to industries in processing hydrocarbon gas and liquid with higher CO₂ content.

- 2 -

Other known techniques, methods and processes for removal of CO₂ from gas stream are for example:

CN102636002 disclosed a low-temperature method for removing CO₂ in natural gas. The method comprising a step of: compressing the natural gas, dehydrating, drying and pre-cooling the natural gas, freezing the natural gas, and freezing the CO₂ into a solid state and attaching so as to remove the CO₂ from the natural gas. The method comprising a refrigeration system, a compressor and a dehydrating and drying tower, a pre-cooling heat exchanger and a freezing heat exchanger, an inlet of the natural gas compressor is used as the inlet of the natural gas and an outlet of the natural gas compressor is communicated with the other end of a heat exchange coil pipe in the pre-cooling heat exchanger through the dehydrating and drying tower; and the other end of the heat exchange coil pipe is communicated with one end of a shell side of the freezing heat exchanger and the other end of the shell side of the freezing heat exchanger is used as a discharging end of the liquefied natural gas.

WO2010080752 disclosed a method for recovering a natural gas contaminated with high levels of carbon dioxide. A gas containing methane and carbon dioxide is extracted from a reservoir containing natural gas, where carbon dioxide comprises greater than 40 vol.% of the extracted gas. The extracted gas is scrubbed with a wash effective to produce a washed extracted gas containing less carbon dioxide than the extracted gas and at least 20 vol.% carbon dioxide. The washed extracted gas is oxidized with an oxygen containing gas in the presence of a partial oxidation catalyst to produce an oxidation product gas containing hydrogen, carbon monoxide, and carbon dioxide. The oxidation product gas is then utilized to produce a liquid methanol product.

WO2005032702 disclosed a method of separating or concentrating hydrocarbon-containing gas mixtures such as hydrogen from hydrocarbons, carbon dioxide from hydrocarbons, nitrogen from hydrocarbons, and hydrocarbons from one another using a selectively permeable membrane. The method is well suited to separate hydrocarbon-

- 3 -

containing mixtures such as those generated by petroleum refining industries, petrochemical industries, natural gas processing, and the like. The membranes exhibit extremely good resistance to plasticization by hydrocarbon components in the gas mixture under practical industrial process conditions.

5 US2006042463 disclosed a method and a system for sweetening a raw natural gas feed stream using a multi-stage membrane separation process, and in embodiments a two-stage membrane separation process. The method and system also include use of a gas turbine which operates with an impure fuel gas stream (such as in the sense of having a relatively high CO₂ and H₂S acid gas contaminant content) as derived from a permeate gas stream obtained in at
10 least the second stage of a membrane separation process, or later stages if more than two stages are employed. In embodiments, the gas turbine is coupled with an electrical generator, which generates electrical power that drives a compressor for the second stage (or higher) of the membrane separation process, as well as other process equipment associated therewith, such as air coolers and process pumps. Alternatively, the gas turbine can be coupled
15 mechanically to the compressor employed. In other embodiments, the power generated by the turbine generator combination can be exported to a local power grid. In other embodiments, the turbine generator is a micro-turbine generator (MTG) which can advantageously be used in applications where space is limited, such as an offshore platform or other oil/gas production facility or on board a floating vessel.

20 JPS6443329 disclosed a method for separating gas employing two types of membranes wherein a mixed gas composed of any of H₂, CO₂ and CO gases and a gas of volatile hydrocarbons is allowed to pass through a first-step membrane module and a second-step membrane module through which high boiling-point components in the volatile hydrocarbon gas pass faster than methane. Subsequently, H₂, CO₂ and CO is separated from
25 the resulting mixed gas by allowing the gas of H₂, CO₂ and CO to pass faster than the volatile hydrocarbon gas components.

- 4 -

US2007214957 disclosed an invention relates to gas separation, in particular to separation of CO₂ from CO₂-rich liquids, particularly from CO₂ absorption liquids used in the removal of CO₂ from off-gases or product flows, such as natural gas or synthesis gas. According to the invention, CO₂ is separated from a CO₂-rich liquid by a method comprising
5 a step wherein, under elevated pressure, said liquid is contacted with a membrane based on polyacetylene substituted with trimethylsilyl groups such that the pressure across the membrane is at least 1 bar and that at least a part of the CO₂ is transported from the liquid through the membrane.

EP2210656 disclosed a separation processes and systems and more specifically to
10 hybrid carbon dioxide separation processes. In one embodiment, the system for the separation or removal of carbon dioxide comprises an apparatus for a selective separation of carbon dioxide (CO₂) from flue gas - typically exhaust gases, syngas or natural gas streams - using one or more so-called CO₂ reverse selective membrane(s) in the first separation unit to enrich a feed gas stream which contains carbon dioxide with CO₂ and by separating other
15 constituents of the gas stream. Thus, the feed gas stream is separated in the first separation unit by CO₂ -reverse-selective separation into a CO₂ -lean gas stream and a CO₂ -enriched gas stream. The CO₂ -enriched gas stream is fed to a second separation unit which is a CO₂ -selective separation unit. The second separation results in a purified CO₂ -rich gas stream and a remaining CO₂ -lean gas stream.

20 Accordingly, an alternative system and process for removal of CO₂ from natural hydrocarbon gas stream is desirable.

SUMMARY OF THE INVENTION

In one aspect of the present invention, the invention disclosed a system for enhancing efficiency in removal CO₂ from natural hydrocarbon gas stream. The system predominantly
25 employs membrane separation technique for removal of CO₂ from hydrocarbon gas and liquids. More specifically, the system comprising a first separation unit installed at a wellhead, such as Wellhead Platform (WHP) and a second separation unit installed at a

- 5 -

Central Processing Platform (CPP). In more detail, in an embodiment, the first separation unit of which is installed at the WHP comprising a sand separator, a heat exchanger, a cooler, a gas/liquid separator, a coalescer, and a first membrane unit. The second separation unit of which is installed at the CPP comprising a separator and coalescer, an adsorbent guard bed, a heater, a particle filter and a second membrane unit. The first separation unit is configured to partially remove CO₂ and other contaminants from hydrocarbon gas and liquid as well as pre-conditioning the hydrocarbon gas and liquid to attain the properties and characteristics to meet the specification set by the second separation unit located at the CPP in order that the hydrocarbon gas and liquid which has been treated by the first separation unit may be transferred for further processing to the second separation unit and wherein the said hydrocarbon gas and liquid has already attained specific properties and characteristics acceptable for further processing by the second separation unit.

In another aspect of the present invention, the invention disclosed a process for enhancing efficiency in removal of CO₂ from natural hydrocarbon gas stream, in particular those natural hydrocarbon gas stream with high level of CO₂ withdrawn from high CO₂ gas reservoir. The processing comprising a step of: i) withdrawing natural hydrocarbon gas and liquid, ii) feeding the said hydrocarbon gas and liquid obtained in i) to a first separation cycle via a first separation unit located at the wellhead, iii) feeding the treated natural gas stream obtained in ii) to a second separation cycle via a second separation unit located at the CPP.

BRIEF DESCRIPTION OF DRAWINGS

Advantages and characteristics of the invention will be appreciated from the following description, in which, as a non-limiting example, some preferable embodiments of the principle of the invention are described, with reference to the accompanying drawings, in which:

FIG. 1 shows schematic illustration of a system for enhancing efficiency in removal CO₂ from natural hydrocarbon gas stream according to the principle of the present invention;

- 6 -

FIG. 2 shows diagram representation of a first separation unit and its process flow at the WHP according to the principle of the present invention;

FIG. 3 shows diagram representation of a second separation unit and its process flow at the CPP according to the principle of the present invention;

5 FIG. 4 shows schematic exemplary representation of the membrane unit of the first separation unit of the present invention; and

FIG. 5 shows schematic representation of removal of CO₂ using a membrane of the membrane unit of the first separation unit of the present invention.

DETAIL DESCRIPTION OF THE INVENTION

10 The present invention disclosed a system and a process for enhancing efficiency in removal of CO₂ from natural hydrocarbon gas stream.

In one aspect of the present invention, the invention disclosed a system for enhancing efficiency in removal CO₂ from natural hydrocarbon gas stream. The system predominantly employs membrane separation technique for removal of CO₂ from hydrocarbon gas and
15 liquids. More specifically, the system comprising a first separation unit installed at a wellhead, such as WHP or a sub-sea wellhead and a second separation unit installed at a CPP. In more detail, in an embodiment, the first separation unit installed at the wellhead comprising a sand separator, a heat exchanger, a cooler, a gas/liquid separator, a coalescer, and a first membrane unit. The second separation unit which is installed at the CPP comprising a
20 separator and coalescer, an adsorbent guard bed, a heater, a particle filter and a second membrane unit. The first separation unit is configured to partially remove CO₂ and other contaminants from hydrocarbon gas and liquid as well as pre-conditioning the hydrocarbon gas and liquid to attain the properties and characteristics to meet the specification set by the second separation unit located at the CPP in order that the hydrocarbon gas and liquid which
25 has been treated by the first separation unit may be transferred for further processing to the second separation unit and wherein the said hydrocarbon gas and liquid has already attained specific properties and characteristics acceptable for further processing by the second separation unit.

- 7 -

In another aspect of the present invention, the invention disclosed a process for enhancing efficiency in removal of CO₂ from natural hydrocarbon gas stream, in particular those natural hydrocarbon gas stream with high level of CO₂ withdrawn from high CO₂ gas reservoir. The processing comprising a step of: i) withdrawing natural hydrocarbon gas and liquid, ii) feeding the said hydrocarbon gas and liquid obtained in i) to a first separation cycle via a first separation unit located at the wellhead, iii) feeding the treated natural gas stream obtained in ii) to a second separation cycle via a second separation unit located at the CPP.

In a first aspect of the invention, the invention disclosed a system for enhancing removal of CO₂ from natural hydrocarbon gas stream, in particular, those natural hydrocarbon gas with high CO₂ content withdrawn from gas reservoirs which produce natural hydrocarbon gas with high CO₂ level. The system comprising a first separation unit installed at the wellhead, such as WHP or a sub-sea wellhead and a second separation unit installed at the CPP. The system may further comprising an Onshore Facilities configured to receive treated natural gas from the second separation unit at the CPP. FIG. 1 shows schematic illustration of an embodiment of a system 100 for enhancing efficiency in removal CO₂ from natural hydrocarbon gas stream according to the principle of the present invention. In this embodiment, the system (100) comprising a Wellhead Platform (WHP) 105, a Central Processing Platform (CPP) 110 located at offshore location and an Onshore Facilities (OF) 115 locating at on-shore location. The WHP 105, the CPP 110 and the OF 115 are connected via pipeline. The WHP 105 comprising a first separation unit 120 configured to process hydrocarbon gas and liquid with high CO₂ content withdrawn from a gas reservoir or multiple reservoirs and to lower the CO₂ content and other contaminants from the said hydrocarbon gas and liquid prior to delivering the said hydrocarbon gas and liquid with targeted lowered CO₂ content to the CPP 110. The CPP 110 comprising a second separation unit 125 configured to receive from the first separation unit 120 natural gas stream of which has been treated to lower CO₂ content and with controlled pressure, temperature and flow rate by the first separation unit 120. More specifically, the first separation unit 120 is configured to lower or remove or partially remove CO₂ from hydrocarbon gas and liquid with high CO₂ content, i.e.

- 8 -

the hydrocarbon gas and liquid having the CO₂ content in the range of 70-90 mole% as well as to pre-conditioning the hydrocarbon gas and liquid to meet other operating specifications and capacities of the second separation unit 125. The CPP 110 transfers the treated natural gas stream which has been treated by both the first separation unit 120 and the second separation unit 125 to OF 115 via pipeline. It will be appreciated by a skilled person the art that OF115 is not an essential element of the present invention as it plays no technical role interm of removal of CO₂ from the natural gas stream according to the principle of the present invention, but simply receive the natural gas which has been treated by the first separation unit 120 and the second separation unit 125. The trated natural gas may be store on site or transfer to other processing facilities or vessels. Further, while preferred, it is also not essential that the transferring of the treated natural gas from the first separation unit 120 and the second separation unit 125 to OF115 is limited to only via pipeline. The treated natural gas may be transferred to OF115 via other means such as a gas transport vessel.

The expression "pre-conditioning" referring herein refers to adjustment of properties and characteristics of the hydrocarbon gas and liquid including its CO₂ level as well as other contaminants, flow rate, pressure, temperature to meet the operating specification and capacity of the second separation unit 125 located at the CPP 110. The properties and characteristics of hydrocarbon gas including natural gas from different wells/reservoirs and different regions can be varied. It is very typical for hydrocarbon gas especially natural gas in Asia to be derived from smaller size wells/reservoirs and often with higher CO₂ level, which can be as high as 90 mole%. Such high level of CO₂ is far exceeded the CO₂ level of feed natural gas pre-set by the conventional gas separation system install at the CPP, consequently rendered the hydrocarbon gas with extremely high CO₂ content unfit for processing at the CPP 110. The application of pre-conditioning using the first separation unit 120 at WHP 105 according to the principal of the present invention provides great advantages including enabling processing of hydrocarbon gas with extremely high CO₂ level. Further, the application of the pre-conditioning using the first separation unit 120 at WHP 105 also made it possible for the feed natural gas to be further processed by the existing conventional CPP without requiring any modifications to the original design and configuration or operating

- 9 -

specification and the CPP 110 can also continue to receive feed gas having normal level of CO₂ withdrawn from reservoirs with lower or normal range of CO₂, i.e. 50 mole% and lower.

In an embodiment, the first separation unit 120 is installed at WHP 105 located on offshore location and is configured to process hydrocarbon gas and liquid withdrawn from smaller gas reservoir, or multiple smaller reservoirs with high CO₂ content wherein the CO₂ content is as high as 90 mole% to treat the hydrocarbon gas and liquid prior to feeding the resulting hydrocarbon mixture to the second separation unit 125 installed at the CPP 110. As shown in FIG. 2, the first separation unit 120 comprising a sand separator 130, a heat exchanger 135, a cooler 140, a gas/liquid separator 145, a coalescer 150, and a first membrane unit 155 connected in a series. The sand separator 130, the heat exchanger 135, the cooler 140, the gas/liquid separator 145, the coalescer 150 are installed before the first membrane unit 155. The hydrocarbon gas and liquid with high CO₂ content is fed into the sand separator 130 to remove sand, sediment or any other solid particles. The characteristics and configuration and mechanism of the sand separator 130 may be of any known configurations which can serve the purposes. Preferably, the sand, sediment or any other solid particles having particle size greater than 0.3 micron are removed at this step. The hydrocarbon gas and liquid which sand, sediment and other solid particles have been removed or partially removed are then passed through to the heat exchanger 135 to reduce the temperature of the hydrocarbon gas and liquid to a required level, preferably to be below 45°C using any known kinds and forms of any heat exchange mediums including waste gas stream, air, water, etc. and heat exchanger of any known configurations. The hydrocarbon gas and liquid which have passed through the heat exchanger 135 are then passed into the cooler 140 and subsequently entered the gas/liquid separator 145. The gas/liquid separator 145 may also be of any known separators. The saturated hydrocarbon gas which exits the gas/liquid separator 145 is then fed into the coalescer 150 to remove water vapor, condensate and hydrocarbon liquids contaminants after which the resultant hydrocarbon gas is then fed into the first membrane unit 155 to obtain the resulting hydrocarbon mixture of which to be fed into the second separation unit 125 located at the CPP 110 for further processing to further remove CO₂ and other contaminants. At the first membrane unit 155, other non-desired permeate

- 10 -

gasses are separated and then fed or re-circulated back into the heat exchanger 135 prior to being disposed of or released to a flare.

It will be appreciated that the key function of the first separation unit 120, according to the principle of the present invention, is to pre-conditioning the hydrocarbon gas and liquid including removal of CO₂ at the wellhead to attain a CO₂ level as well as other characteristics to be within the range that will meet the operating specification of the second separation unit 125 located at the CPP 110 or the operating specification of the conventional pre-existing CO₂ removal system at the CPP 110. The pre-conditioning of the hydrocarbon gas and liquid having high CO₂ content at the first separation unit 120 enable the hydrocarbon gas which has been treated by the first separation unit 120 to be fed as feed gas to the second separator unit 125 of which has been designed and calibrated to treat hydrocarbon gas and liquid with specific level of CO₂ as well as other specific characteristics without requiring modification of the current design and operating system of the existing processing system at the CPP 110. Accordingly, according to the principle of the present invention, in a further embodiment, the first separation unit 120 may further comprising any other known elements, separators of which may be strategically placed along the above described processing flow to remove different contaminants at different steps of the processing flow. Further, in an embodiment, it is possible for the first separation unit 120 to comprise more than one or multiple units of first membrane units 155, wherein each first membrane unit 155 is configured to function in term of removing CO₂ equally, independently or in compliment to one another to achieve the set target, i.e. the level of CO₂ content, flow rate, pressure and temperature of the hydrocarbon gas acceptable for further processing by the second separator unit 125 located at CPP 110. The flow rate, pressure and temperature of the feed hydrocarbon gas and liquid at the first separator unit 120 are monitored and controlled by a controller 161 of which could be a computerized controller or manually operated controller communicates or links to the first separation unit 120 such as the feed hydrocarbon gas and liquid are fed into the second separation unit 125 under controlled pressure, temperature and flow rate. Preferably, the operating pressure and temperature at the first separation unit 120 are 25-65 bar and 40-100°C, respectively. It will be appreciated by a skilled person in the art that application of

- 11 -

the system according to the present invention allows opportunities to exploit natural hydrocarbon gas with high CO₂, which usually sealed off at the well because it is unfit for processing by the existing processing system installed at the CPP 110. The current invention would, therefore, present opportunities for increasing productivity of natural gas as natural gas with high CO₂ content can now be processed. Further, due to the fact the system according to the present invention requires no modification to the current processing system, the system according to the present invention not only avoid the cost of modification of the current processing system [which would be far more costly than application of the present invention], the existing processing system will also be able to continue handling of hydrocarbon gas and liquid having normal range of CO₂ content.

As described, in an exemplary embodiment, the system 100 for enhancing efficiency in removal CO₂ from natural hydrocarbon gas stream with high CO₂ content according to the principle of the present invention comprising a Wellhead Platform (WHP) 105 located on offshore location, a Central Processing Platform (CPP) 110 located at offshore location and may further comprising an Onshore Facility (OF) 115 located at on-shore location. The CPP 110 comprising a second separation unit 125 configured to receive from the first separation unit 120 natural gas stream of which has been treated by the first separation unit 120. According to an embodiment of the present invention, as shown in FIG 3, the second separation unit 125 comprising a separator and coalescer unit 160, an adsorbent guard bed 165, a heater 170, a particle filter 175, and a second membrane unit 180. It is possible for the second separation unit 125 to also comprising a separate controller rather sharing the same controller 161 with the first separation unit 120.

The application of the separator and coalescer unit 160, the adsorbent guard bed 165, the heater 170, the particle filter 175, and the second membrane unit 180 at the CPP 110 are known. Basically, traditional membranes cannot stand against liquid and heavy hydrocarbon components contained in the gas stream. More specifically, traditional membrane at the membrane unit at the CPP110 is cellulosic, polysulfone and polyimide-based membrane which has relatively short life span and susceptible to damages or reduction in efficiencies

- 12 -

upon contacting with water, natural gas liquids, heavy hydrocarbons and CO₂ gas. The traditional membrane often undergoes plasticization known as "CO₂ induced plasticization" resulting in a reduction in separation efficiencies during operation. Due to this, the Adsorbent Guard Bed 165 is, therefore, required as a pre-treatment unit at the CPP 110 to cut-off heavy hydrocarbon and other components such as water from the feed natural gas. The heater 170 is configured to superheat and control the temperature of the membrane restricting any water from entering the second membrane unit 180. The features and characteristics and components of the second separation unit 125 are known. Therefore, these elements will not be described. The second separation unit 125 at the CPP 110 receives from the first separation unit 120, hydrocarbon gas which has been pre-treated to meet its operating specification. It should be noted, however, that the configuration and components of the first separation unit 120 at the WHP 105 are designed based on the availability of limited footprint and power supply. Due to an exceptional characteristics of the membrane and its arrangement in accordance with the principle of the present invention, the Adsorbent Guard Bed 165 which is a crucial component of the conventional system for removal of CO₂ from natural gas stream and of which covers more than 50% of CPP110 designed footprint is no longer a necessity at the first separation unit 120 of the present invention. Therefore, it is possible to attain a more compact overall footprint at the WHP 105 than that of the CPP110. This, once again, proves that the system 100 for enhancing efficiency in removal CO₂ from natural hydrocarbon gas stream according to the principle of the present invention is more flexible in removal of CO₂ from natural hydrocarbon gas stream. That is, the system 100 for enhancing efficiency in removal CO₂ from natural hydrocarbon gas stream according to the principle of the present invention will be able to process natural hydrocarbon gas from different wells with variable CO₂ content. That is, wherein natural hydrocarbon gas with normal range of CO₂ content, i.e. at 40 to 50 mole% may be processed by the second separator unit 125 and wherein natural hydrocarbon gas with high level of CO₂ content, i.e. in excess of 50 mole% to as high as 90 mole%, may be processed by the first separator unit 120 combined with the second separator unit 125 of the present system 100 for enhancing efficiency in removal CO₂ from natural hydrocarbon gas stream.

- 13 -

FIGs. 4-5, show an exemplary schematic representation of the first membrane unit 155 and the functioning of the membrane according to the principle of the present invention wherein the first membrane unit 155 is configured to remove CO₂ from the hydrocarbon gas stream. Permeate gas generated in this step is discharged by the membrane unit 155 and
5 recirculate to the heat exchanger 135 prior to being disposed of or release to a flare. The first membrane unit 155 at the first separation unit 120 comprising a plurality of membrane modules 190 and inside each membrane module 190 there are disposed a plurality of semi-permeable fluid separation membranes 156 configured to influence separation of gaseous mixture through solution -diffusion transport mechanism, wherein the hydrocarbon gas
10 mixture is brought into contact with the said semi-permeable fluid separation membranes 156 under predetermined pressure such that a portion of CO₂ is selectively dissolved and diffused through the semi-permeable fluid separation membranes 156 resulting in enriched fraction of CO₂ on one side of the semi-permeable fluid separation membranes 156 and depleted fraction of CO₂ remains on the other side of the semi-permeable fluid separation membranes 156 as
15 shown in FIG. 5. Preferably, the semi-permeable fluid separation membrane 156 used in an embodiment of the present invention is a fluid separation membrane made from composite membrane, preferably derived from a class of semi-crystalline engineered thermoplastics with outstanding thermal and chemical resistance capacity. Preferably, the semi-permeable fluid separation membrane 156 is an asymmetrical membrane selected from flat sheet membrane,
20 tube membrane or hollow fiber membrane. The semi-permeable fluid separation membrane 156 comprising a functionalized ultra-thin selective layer formed from a dense hydrophobic, oleophobic or amphiphobic and CO₂ selective layer 157 arranged on a bed of micro-porous substrate 158 to offer optimum resistant to water, natural gas liquids, hydrogen sulfide and heavy hydrocarbon. In the embodiment as shown in FIG. 4, the membrane unit 155
25 comprising a plurality of membrane modules 190 disposed within the said first membrane unit 155. Each membrane module 190 at one end communicates to a feeding pipeline so as to receive feed gas [after having been treated by the coalesce 150] being fed into the first membrane unit 155, while connect to another pipeline at another end so as to discharge treated natural gas [product gas] out of the membrane unit 155. The number of membrane
30 modules 190 and the configuration of their arrangement could be tailored differently to

- 14 -

suitable the volumetric flow of the feed gas and the available footprint at the wellhead. Preferably, the said plurality of membrane modules 190 are arranged as two or more groups in which each group comprising of a plurality of membrane modules 190 and each membrane module 190 in each group while connected to its respective feeding pipe share a common
5 main pipe 191 delivering the feed gas into the first membrane unit 155. With such arrangement and configuration, each group of membrane modules 190 able to process the feed gas independently from one another. This allows a better and more convenience maintenance because any one group of the membrane modules 190 may be shut down for maintenance or repair while the remaining groups continue to process the feed gas.
10 Consequently, it can reduce down-time of the system and would not substantially affect gas product output should shutting down of any one group of the membrane modules 190 is needed. While it is possible to provide the first membrane unit 155 with only a single group of a plurality of membrane modules 190 and each individual module may be selectively shut down in similar manner as with shutting down of a group of membrane modules 190, it is less
15 preferred because it could affect the product output per time unit. Further, as mentioned earlier providing a multiple units of the first membrane units 155 is also possible and that each membrane unit may comprise a single or multiple groups of membrane module 190 are also possible. Accordingly, selective shutting down of the entire membrane unit 155 among the multiple units thereof or shutting down of only one specific group of a plurality of
20 membrane modules 190 among the multiple groups thereof or shutting down of one specific module among a single group for maintenance would be all possible without completely shutting down of the entire system.

Again, as shown in FIG. 4, disposed inside each membrane module 190 are multiple semi-permeable fluid separation membranes 156 configured to influence separation of gaseous
25 mixture through solution –diffusion transport mechanism, wherein the hydrocarbon gas mixture is brought into contact with the said semi-permeable fluid separation membrane 156 under predetermined pressure such that a portion of CO₂ is selectively dissolved and diffused through the semi-permeable fluid separation membrane 156 resulting in enriched fraction of CO₂ on one side of the semi-permeable fluid separation membrane 156 and depleted fraction

- 15 -

of CO₂ remains on the other side of the semi-permeable fluid separation membrane 156 as shown in FIG. 5.

It will be appreciate by a skilled person in the art that while the exemplary examples of the principle of the present invention discussed utilization of the first membrane unit 155 at the WHP for pre-treating natural hydrocarbon gas prior to subjecting to further processing at the CPP 110, the first membrane unit 155 according to the principle of the present invention can also be applied to wellhead platform or any other types of wellhead such as sub-sea wellhead.

In a second aspect of the present invention, the present invention disclosed a process for removal of CO₂ from hydrocarbon gas and liquid, especially those with high CO₂ content, for example those with the CO₂ level in the range of 50 mole% and over or up to 90 mole%. The process using the system 100 as described above. The process for removing CO₂ from natural hydrocarbon gas and liquid stream using the system (100) according to present invention, comprising subjecting the natural hydrocarbon gas and liquid to a first separation cycle to lower the CO₂ content and contaminants to achieve a targeted level thereof follows by subjecting the hydrocarbon gas obtained therefrom to a second separation cycle to further remove the CO₂ content and contaminant to a desired level. In more detail, the process comprising the following steps:

- i) withdrawing of hydrocarbon gas and liquid from well or wells;
- ii) subjecting the hydrocarbon gas and liquid obtained in step i) to a first CO₂ and contaminant removal cycle by feeding the hydrocarbon gas and liquid with high CO₂ content of up to 90 mole% to the first separation unit 120 installed at the WHP 105 located at offshore location to remove or partially remove or lower the CO₂ content including contaminants to be within the range or level of the pre-set operating specification at the CPP 110;
- iii) subjecting the resultant saturated hydrocarbon gas obtained in step ii) with lowered CO₂ and contamination level to a second CO₂ and contaminant removal cycle using the second separation unit 125 installed at the CPP110 located at a remote offshore location to further remove CO₂ and contaminants from the hydrocarbon gas and to

- 16 -

bring the CO₂ level down to the required level or to meet the required specifications;
and

iv) delivering the resulting hydrocarbon gas obtained in step iii) to the Onshore Facilities 115 located on shore.

5 In more detail, hydrocarbon gas and liquid with high CO₂ content are withdrawn from gas reservoir/well or multiple reservoirs/wells using any known techniques, methods and apparatuses. Hydrocarbon gas and liquid obtained therefrom with CO₂ content up to 90 mole% are then fed to the first separation unit 120 installed at the WHP 105 to remove, partially remove or lower the CO₂ content as well as other contaminants to be within the range
10 or level corresponding to the pre-set operating specification at the CPP 110, preferably the CO₂ is lowered to be 50 mole% and under. The initial removal of the CO₂ as well as other contaminants at the first separation unit 120 is carried out under controlled pressure, temperature, and flow rate of which are monitored and controlled by computerized controller 161 linked to the first separation unit 120. Preferably, the operating pressure and temperature,
15 at the first separation unit 120 is 25-65 bar and 40-100°C, respectively. The flow rate is variable according to the source of the natural gas. Of course, these specific parameters of operating pressure, temperature and flow rate may be readjusted or recalibrate or variable as needed. During the first separation cycle, the hydrocarbon gas and liquid are brought into contact with the membrane arranged inside each membrane module 190 of the first membrane
20 unit 155 of the first separation unit 120. Each membrane module 190 comprising a plurality of semi-permeable membrane 156 configured to influence separation of gaseous mixture through solution –diffusion transport mechanism. The hydrocarbon gas mixture is brought into contact with the said semi-permeable membrane 156 under predetermined pressure such that a portion of CO₂ is selectively dissolved and diffused through the membrane resulting on
25 enriched fraction of CO₂ on one side of the membrane and depleted fraction of CO₂ remains on the other side of the membrane. The features and configurations of the membrane are as earlier described. As well, the features and configurations of the first separation unit 120 are as previously described. In an embodiment, the hydrocarbon gas and liquid may be subjected to treatment by one or more first membrane units 155 installed at the first separation unit 120

- 17 -

to bring the CO₂ content as well as other contaminants down to the level suitable and acceptable for further processing by the second separation unit 125. The saturated natural gas stream obtained from step ii) having CO₂ level and other characteristics that are fit for further processing by the second separation unit 125 are then fed, under controlled pressure, temperature and flow rate, to the second separation unit 125 to further remove CO₂ and bring the CO₂ level down to meet the requirements or the industry specifications. During the second separation cycle, i.e. at the second separation unit 125, the hydrocarbon gas of which has been treated by the first separation unit 120 is once again subjected to further treatment by the second separation unit 125. That is, the obtained hydrocarbon gas or feed gas is fed to the separator and coalescer unit 160, the adsorbent guard bed 165, the heater 170, the particle filter 175, and the second membrane unit 180 in respective sequence at the CPP 110. The resulting hydrocarbon gas obtained in step iii) is then delivered to the onshore facilities 115 via pipeline. Permeate gas generated from the process are released to a flare. As mentioned earlier that onshore facilities 115 is not an essential element of the present invention. Accordingly the treated hydrocarbon gas obtained in step iii) may be delivered to other processing facilities and not necessary located on shore or to the onshore facilities 115 mentioned herein.

It will be appreciated from the foregoing description that the system and process for enhancing efficiency in removal of CO₂ from natural hydrocarbon gas stream according to the principle of the present invention offer advantage in term of enabling utilization of hydrocarbon gas with high CO₂ content up to 90 mole% which usually left unutilized as the currently used system is unable to process hydrocarbon gas with such high CO₂ content. Further, the system and process according to the principle of the present invention is designed to also compatible with the existing operating specification and configuration so that no or only minimal modification to the existing separation system at the CPP is required to avoid cost relating to modification of the currently used system. Accordingly, the objective of the invention as set out above is considered to have been met.

- 18 -

CLAIMS

We claim:

1. A system (100) for removing CO₂ from natural hydrocarbon gas and liquid comprising:
 - 5 - a first separation unit (120) installed at a wellhead (105) communicates to a gas reservoir or multiple gas reservoirs, and located at an offshore location;
 - a second separation unit (125) installed at a Central Processing Platform (110) and located at a remote offshore location;wherein the first separation unit (120) is connected to the second separation unit (125)
10 via pipeline; the first separation unit (120) is configured to process hydrocarbon gas and liquid to lower the CO₂ content and contaminants prior to feeding the said hydrocarbon gas and liquid with targeted lowered CO₂ content and contaminant and with controlled pressure, temperature and flow rate to the second separation unit (125) to be further processed to further remove the CO₂ content and contaminants by the second separation unit (125)
- 15 2. The system (100) according to claim 1, wherein the first separation unit (120) comprising a sand separator (130), a heat exchanger (135), a cooler (140), a gas/liquid separator (145), a coalescer 150, and one or more first membrane units (155) connected in a series; the said heat exchanger 135, the cooler (140), the gas/liquid separator (145), the coalescer (150) are disposed prior to the said one or more first membrane units (155).
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3. The system (100) according to claim 2, wherein each of the multiple units of the first membrane unit (155) at the first separation unit (120) is configured to remove CO₂ equally, independently or in compliment to one another to achieve a targeted level of CO₂ content of the hydrocarbon gas acceptable for further processing by the second separator unit
25 (125) located at CPP (110).
4. The system (100) according to claim 3, wherein the membrane unit (155) at the first separation unit (120) comprising one or more groups of a plurality of membrane modules

- 19 -

(190) arrange inside the said first membrane unit (155) and each membrane module (190) or each group of membrane modules (190) is configured to process the feed gas independently from one another.

5 5. The system (100) according to claim 4, wherein the membrane module (190) of the first membrane unit (155) at the first separation unit (120) comprising a plurality of semi-permeable fluid separation membranes (156) configured to selectively dissolved and diffused CO₂ contained in the hydrocarbon gas brought into contact with the semi-permeable fluid separation membrane (156) to attain enriched fraction of CO₂ on one side of the semi-permeable fluid separation membrane (156) and depleted fraction of CO₂ on the other side of the semi-permeable fluid separation membrane (156).
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6. The system (100) according to claim 5, further comprising a controller configured to control controlled pressure, temperature and flow rate of the hydrocarbon gas being transferred from the first separation unit (120) to the second separation unit (125).
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7. The system (100) according to claim 5 further comprising an Onshore Facilities configured to receive treated hydrocarbon gas from the second second separation unit.
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8. The system (100) according to claim 5, wherein the semi-permeable fluid separation membrane (156) is a composite membrane made from semi-crystalline engineered thermoplastics with thermal and chemical resistance capacity.
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9. The system (100) according to claim 8, wherein the semi-permeable fluid separation membrane (156) is an asymmetrical membrane selected from flat sheet membrane, tube membrane or hollow fiber membrane.

10. The system (100) according to claim 9, wherein the said semi-permeable fluid separation membrane (156) comprising a dense hydrophobic, oleophobic and CO₂-selective layer (157) arrange on a bed of micro-porous substrate (158).
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- 20 -

11. The system (100) according to claim 10, wherein the second separation unit (125) is configured to remove the CO₂ content and contaminants from the hydrocarbon gas pre-treated by the first separation unit (120) or natural hydrocarbon gas having a range of CO₂ and contaminant fit for processing at the Central Process Platform (110), the second separation unit (125) comprising a separator and coalescer (160), an adsorbent guard bed (165), a heater (170), a particle filter (175), and a second membrane unit (180) arranged in respective sequence.

12. A process for removing CO₂ from natural hydrocarbon gas and liquid stream using the system (100) according to any one of claims 1-11, comprising subjecting the natural hydrocarbon gas and liquid to a first separation cycle to lower the CO₂ content and contaminants to achieve a targeted level thereof followed by subjecting the hydrocarbon gas obtained therefrom to a second separation cycle to further remove the CO₂ content and contaminant to a desired level; the first separation cycle is located at a wellhead (105) and the second separation cycle is located at a Central Processing Platform (110).

13. The process for removing CO₂ from natural hydrocarbon gas and liquid stream according to claim 12, wherein the process comprising a step of:

- i) withdrawing of hydrocarbon gas and liquid from well or wells;
- ii) subjecting the hydrocarbon gas and liquid obtain in step i) to a first separation cycle by feeding the said hydrocarbon gas and liquid to the first separation unit (120) installed at the wellhead (105) located at offshore location to partially remove or lower the CO₂ content including contaminants to a targeted level;
- iii) subjecting the natural gas stream obtain in step ii) to a second separation cycle by feeding the said natural gas stream having targeted level of CO₂ and with controlled pressure, temperature and flow rate to the second separation unit (125) installed at the Central Processing Platform (110) located at a remote offshore location to further remove or lower CO₂ from the said natural gas stream and to bring the CO₂ level down to the required level or to meet the required specification; and
- iv) delivering the resulting hydrocarbon gas obtained in step iii) to desired locations including Onshore Facilities (115) located on shore.

- 21 -

14. The process according to claim 13, wherein the hydrocarbon gas and liquid at the first separation unit (120) of the first separation cycle having a CO₂ content up to 90 mole% and the CO₂ content of said hydrocarbon gas is lowered to 50% mole and under prior to delivering the said hydrocarbon gas to the second separation unit (125) of the second separation cycle.

15. The process according to claim 14, wherein the hydrocarbon gas and liquid is brought into contact with the semi-permeable fluid separation membrane (156) disposed at the first separation unit (120) during the first separation cycle under controlled pressure, temperature and flow rate such that a portion of CO₂ is selectively dissolved and diffused through the semi-permeable fluid separation membrane (156) resulting in enriched fraction of CO₂ on one side of the membrane (156) and depleted fraction of CO₂ remains on the other side of the semi-permeable fluid separation membrane (156).

16. The process according to any one of claims 12 to 15, wherein the pressure and temperature of the hydrocarbon gas and liquid are monitored and controlled by a controller (161) linked to the first separation unit (120) and the second separation unit (125).