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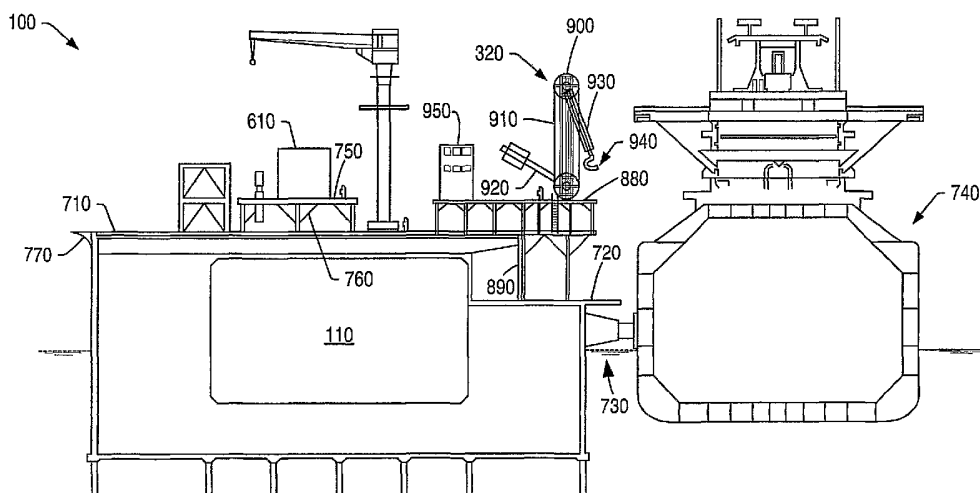
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(54) Title: UNLOADING EQUIPMENT SYSTEMS FOR LIQUEFIED NATURAL GAS STORAGE STRUCTURE



(57) Abstract: An off-shore liquefied natural gas structure may receive, store, and process liquefied natural gas from carriers. A structure may be a gravity base structure. A structure may include liquefied natural gas transfer equipment. Transfer equipment may offload liquefied natural gas from a carrier berthed on the structure. Equipment and/or piping in the structure may be capable of gravity draining to liquefied natural gas storage tanks.

UNLOADING EQUIPMENT SYSTEMS FOR LIQUEFIED
NATURAL GAS STORAGE STRUCTURE

This application claims the benefit of U.S. Provisional Application Serial No. 60/515,470, filed October 29, 2003.

Background of the Invention

Field of the Invention

The invention generally relates to structures configured to store liquefied natural gas and distribute natural gas. More specifically the invention relates to liquefied natural gas processing.

Description of Related Art

Natural gas is becoming a fuel of choice for power generation in the U.S. and other countries. Natural gas is an efficient fuel source that produces lower pollutant emissions than many other fuel sources. Additionally, gains in efficiency of power generation using natural gas and the relatively low initial investment costs of building natural gas based power generation facilities, make natural gas an attractive alternative to other fuels.

Distribution and storage of an adequate supply of natural gas are important to the establishment of power generation facilities. Because of the high volumes involved in storing of natural gas, other methods of storing and supplying natural gas have been used. The most common method of storing natural gas is in its liquid state. Liquefied natural gas ("LNG") is produced when natural gas is cooled to a cold, colorless liquid at -160 °C (-256 °F). Storage of LNG requires much less volume for the same amount of natural gas. A number of storage tanks have been developed to store LNG. In order to use LNG as a power source, the LNG is converted to its gaseous state using a re-vaporization process. The re-vaporized LNG is then distributed through pipelines to various end users.

One advantage of LNG is that LNG may be transported by ship to markets further than would be practical with pipelines. This technology allows customers who live or operate a long way from gas reserves to enjoy the benefits of natural gas. Importing LNG by ships has led to the establishment of LNG storage and re-vaporization facilities at on-shore locations that are close to shipping lanes. The inherent dangers of handling LNG make such on-shore facilities less desirable to inhabitants who live near the facilities. There is therefore a need to explore other locations for the storage and processing of LNG.

Summary of the Invention

The invention provides a liquefied natural gas storage structure positioned in a body of water comprising a body, one or more liquefied natural gas storage tanks contained within the body, wherein at least a portion of the bottom surface of the body rests upon a portion of the bottom of the body of water.

In a preferred embodiment, the structure further comprises liquefied natural gas transfer equipment coupled to the body, wherein the liquefied natural gas transfer equipment is configured to transfer liquefied natural gas from a liquefied natural gas carrier to at least one liquefied natural gas storage tank.

The invention also provides a method of using a liquefied natural gas storage structure, as described herein, in a body of water, comprising: receiving liquefied natural gas from a liquefied natural gas carrier; storing the liquefied natural gas in one or more liquefied natural gas storage tanks; and processing the liquefied natural gas to natural gas using vaporization equipment.

In an embodiment, LNG receiving, storage and processing facilities are positioned in an offshore location. The LNG

storage and processing facility, in one embodiment, is a gravity base structure. A gravity base structure is a structure that at least partially rests upon the bottom of a body of water and partially extends out of the body of water. The gravity base structure includes equipment for receiving, storing, and processing LNG.

In one embodiment, an LNG structure includes a body disposed in a body of water. The body at least partially rests upon a bottom of the body of water, while an upper surface of the body extends above the surface of the water. One or more LNG storage tanks are contained within the body. Equipment for transfer and processing of LNG is disposed on the upper surface of the body.

In one embodiment, docking equipment may be disposed on an upper surface of the body. The docking equipment may be configured to couple an LNG carrier to the body. By placing the docking equipment directly on the body, instead of using, for example, separate mooring platforms, the LNG carrier may be coupled closer to the body. Coupling an LNG carrier close to the body may facilitate transfer of LNG from the LNG carrier to the LNG storage tanks. Additionally, the body may also provide some protection from waves while the LNG carrier is docked alongside the body.

The body of the LNG structure at least partially rests on the bottom of a body of water. In one embodiment, projections extend from the bottom of the LNG structure body. The projections may contact the bottom of the body of water, and, in some embodiments, may become at least partially embedded in the bottom of the body of water. The projections may be configured to substantially inhibit movement of the structure due to waves and weather conditions. In addition to projections, a system of ballast storage areas, also referred to as ballast cells, may be disposed throughout the

body. In some embodiments, liquid ballast (e.g., water), solid ballast (e.g., sand), or a combination of liquid and solid ballast may be used to fill the ballast storage areas. Ballast may be used to maintain the structure on the bottom of the body of water.

Vaporization equipment may be disposed on the body. Vaporization equipment is used to vaporize LNG to natural gas. In one embodiment, vaporization equipment includes a heat exchange vaporization system. A heat exchange vaporization system may, in some embodiments, use water from the body of water to convert LNG to natural gas. Water from the body of water may be obtained using a variety of water intake systems. The water intake systems may be configured to reduce the amount of sea life and debris that enters the heat exchange vaporization system.

The various components of LNG transfer, storage, and processing may be disposed on an upper surface of the body. In one embodiment, one or more platforms may be constructed on the upper surface of the body. Various LNG storage, transfer, and processing equipment may be disposed on top of platforms, rather than directly on the upper surface of the LNG structure. In some embodiments, one or more platforms may be at a height of at least about 5 meters above the upper surface of the body. In this manner, the equipment may be protected from water running over the structure during extreme weather conditions. Additionally, wave deflectors may be positioned on at least a portion of the edge of the LNG structure body. Wave deflectors may extend outward from the sidewalls of the structure. In this manner, waves that impact the side of the structure may be inhibited from flowing over an upper surface of the body.

In one embodiment, living quarters, flare towers, and export line metering equipment may be disposed on the body of

the structure. By placing these areas directly on the body, the use of auxiliary platforms to hold these structures may be avoided, therefore reducing construction costs.

Typical LNG carriers have a net LNG capacity ranging from 125,000 cubic meters to about 165,000 cubic meters. Additionally, it is expected that LNG carriers of up to about 200,000 cubic meters in net storage capacity may be available in the future. To be able to accommodate a wide variety of LNG carriers, the LNG capacity of the LNG structure may be optimized based on a number of factors. Some of the factors for determining the optimal storage capacity include the LNG capacity of one or more predetermined LNG carriers, the desired peak capacity of the structure for converting LNG to natural gas, the rate at which LNG from an LNG carrier is transferred to one or more LNG storage tanks, and the cost associated with operating the structure. Based on the known size of currently used LNG carriers and an expected peak natural gas production rate of at least 1 billion cubic feet per day (1,960 m³/h LNG), it is estimated that an optimal net storage capacity of the LNG structure may be about 180,000 cubic meters.

Brief Description of the Drawings

Advantages of the present invention will become apparent to those skilled in the art with the benefit of the following detailed description of embodiments and upon reference to the accompanying drawings, in which:

FIG. 1 depicts a top view of an embodiment of the structure;

FIG. 2 depicts a cross-sectional view of a storage tank and ballast storage areas in a structure;

FIG. 3 depicts a top view of embodiments of the structure and water inlets and outlets;

FIG. 4 depicts a cross-sectional view of a water inlet positioned on a structure;

FIG. 5 depicts a representation of an embodiment of the vaporization process;

FIG. 6 depicts a cross-sectional view of an embodiment of a structure;

FIG. 7 depicts a top view of an embodiment of the structure; and

FIG. 8 depicts a cross-sectional view of a water inlet positioned on a structure.

While the invention is susceptible to various modifications and alternative forms, specific embodiments thereof are shown by way of example in the drawings and will herein be described in detail. It should be understood that the drawings and detailed description thereto are not intended to limit the invention to the particular form disclosed, but on the contrary, the intention is to cover all modifications, equivalents, and alternatives falling within the spirit and scope of the present invention as defined by the appended claims.

Detailed Description of the Invention

An offshore liquefied natural gas ("LNG") receiving and storage structure may allow LNG carriers to berth directly alongside the structure and unload LNG. The LNG structure may include one or more tanks capable of storing LNG. The LNG structure may transfer LNG from the tanks to an LNG vaporization plant disposed on the structure. The vaporized LNG may then be distributed among commercially available pipelines.

FIG. 1 depicts an embodiment of the LNG structure. An LNG structure 100 may have a layout that includes LNG tanks 110 on the structure with vaporization process equipment 120 and utilities, docking equipment, living

quarters 130, flares 140, vents 150, metering equipment 160, and pipelines 170 for exporting natural gas. The living quarters 130, vaporization plant 120, and/or other process equipment may be positioned on an upper surface of the structure 100, such as on an upper surface of unit 180 and/or unit 190. The layout may be designed according to Fire/Explosion Risk assessment guidelines. In an embodiment, the layout of the structure may be designed to maximize safety of the living quarters.

In some embodiments, living quarters may be positioned on the structure. The living quarters may be positioned proximate an opposite end from the flare and/or vent. The living quarters may not be positioned proximate the heat exchangers and/or recondensers. In certain embodiments, living quarters on the structure may be positioned to be proximate living quarters on an LNG carrier during unloading. Aligning living quarters on the structure with living quarters on the carrier may maximize safety. The living quarters may be substantially resistant to fire, blast, smoke, etc. The living quarters may be reinforced to substantially withstand explosion overpressure. In an embodiment, the living quarters may be designed to inhibit the ingress of gas and smoke.

In an embodiment, the living quarters may be positioned on a separate platform in the body of water. The platform may be coupled to the structure by a connecting bridge. Overall there may be little or no difference between the risks to living quarters on the structure and living quarters on a separate platform. In an embodiment, living quarters on the structure are at least partially protected from waves by the structure.

The body of the LNG structure may include one or more units. In some embodiments, the units may be, for

example, but not limited to, steel-reinforced concrete units, steel jackets, and the like and combinations thereof. The one or more units may square, rectangular, partially spherical, and the like and combinations thereof. The structure may include only one unit. In an embodiment, the structure may include two units. The one or more units may be coupled together. The units may be substantially similarly sized. More than one unit may be used because of ease of construction, soil conditions, restricted space available in existing graving docks, and/or difficulties with tow out and installation. The units may be built onshore, towed to the site, and set down at a desired location using well-proven construction methods and technology as known to one skilled in the art. In an embodiment, the units may be separately towed to an offshore site. The units may be towed together to a site.

In certain embodiments, the LNG structure may be composed of two or more units, each unit including one or more LNG storage tanks. The units may be placed end to end to form the structure. A bridge structure may couple units together. LNG storage tanks 110 in each unit 180, 190 may be coupled together. See FIG. 1. The two or more units may be coupled together. A gap 200 between units 180, 190 may be closed off to prevent erosion of the seabed between the units. Each unit 180, 190 may contain different equipment, living quarters 130, and/or liquefied natural gas tanks 110. In certain embodiments, living quarters 130 may be on one unit 180 and a vaporization plant 120 and other process equipment may be on a different unit 190. The docking equipment may be distributed on one or more units, such as on unit 180 and/or unit 190.

FIG. 7 depicts an embodiment of an LNG structure of the present invention. An LNG structure 100 may have a layout that includes LNG tanks 110 on a unit 180 of the structure. While the tanks in FIG. 7 are depicted as cylindrical tanks, the tanks may be, for example, but not limited to, cylindrical, square, rectangular, partially spherical, irregularly shaped, and the like and combinations thereof. The vaporization process equipment 120 and utilities, docking equipment, living quarters 130, flares 140, vents 150, metering equipment 160 and pipelines 170 for exporting natural gas are on a unit 190 of the structure. The living quarters 130, vaporization plant 120, and/or other process equipment may be positioned on an upper surface of the structure 100, such as on an upper surface of unit 190. The units may be, for example, but not limited to, concrete units, also referred to as concrete caissons, steel jackets, and the like and combinations thereof. The units may be, for example, but not limited to, square, rectangular, partially spherical, and the like and combinations thereof. The units may be coupled together. The docking equipment may be distributed on one or more units, such as on unit 180 and/or unit 190. The units may be placed end to end to form the structure. A bridge structure may couple units together. LNG storage tanks 110 in unit 180 may be coupled together. The units may be coupled together. A gap 200 between units 180 and 190 may be closed off to prevent erosion of the seabed between the units.

In some embodiments, the LNG structure may be composed of more than one unit, such as two units, comprising concrete units, steel jackets, and the like and combinations thereof. The units may be square, rectangular, partially spherical, and the like and combinations thereof. In some embodiments, one of the units may be square or rectangular and comprise

one or more tanks that can be, for example, but not limited to, cylindrical, rectangular, partially spherical, irregularly shaped, and the like and combinations thereof. For example, in some embodiments comprising two units, one of the two units may be a concrete square or rectangle comprising two cylindrical tanks. The other unit may be a concrete square or rectangle and comprise the vaporization process equipment and utilities, living quarters, flares, vents, metering equipment and pipelines. Docking equipment may be on one or more of the units. The units may be coupled together.

In some embodiments, an LNG structure of the present invention may be composed of more than one unit, such as three units, where the units may be, for example, but not limited to, concrete units, also referred to as concrete caissons, steel jackets, and the like and combinations thereof. The units may be, for example, but not limited to, square, rectangular, partially spherical, and the like and combinations thereof. The units may be coupled together. In some embodiments, the LNG structure may be comprised of three units where all three units are concrete units or caissons with two of the concrete units or caissons comprising one or more LNG tanks, and the third concrete unit or caisson comprising the vaporization process equipment and utilities, living quarters, flares, vents, metering equipment and pipelines. Docking equipment may be on one or more of the units. Such an embodiment may allow for the two units comprising the one or more LNG tanks to be reduced in length and the unit comprising the utilities may be smaller as well compared to a structure comprising two units. In some embodiments, non-cryogenic LNG components may be placed on the third unit. The concrete units may be, for example, but not limited to, square, rectangular, partially spherical, and

the like and combinations thereof. The units may be coupled together.

In some embodiments, an LNG structure of the present invention may be composed of more than one unit, such as two units, where one unit comprises a concrete unit or caisson and the other unit comprises a steel jacket. The concrete unit may be, for example, but not limited to, square, rectangular, partially spherical, and the like and combinations thereof, and comprise one or more tanks that can be, for example, but not limited to, cylindrical, rectangular, partially spherical, irregularly shaped, and the like and combinations thereof. The steel jacket unit may be, for example, but not limited to, square, rectangular, partially spherical, and the like and combinations thereof. For example, one of the two units can be a concrete square or rectangle comprising two round tanks. The other unit may be a steel jacket unit and comprise the vaporization process equipment and utilities, living quarters, flares, vents, metering equipment and pipelines. Docking equipment may be on one or more of the units. The units may be coupled together. In some embodiments, one or more steel jackets may be utilized to provide additional units that provide, for example, but not limited to, a separate unit for vaporization process equipment and utilities, flares and vents, a separate unit for metering equipment and pipelines, and a separate unit for living quarters. Docking equipment may be on one or more of the units. The units may be coupled together.

The phrase "steel jacket" or "steel jacket unit" referred to herein means any steel jacket that can be utilized according to an embodiment of an LNG structure disclosed herein. Steel jacket refers to any steel template, space-frame support apparatus, platform and/or structure utilized to support various processing equipment

typically utilized for off-shore production of hydrocarbons, LNG, and the like and combinations thereof. Examples of companies that may be able to provide steel jackets suitable for use in an embodiment of an LNG structure disclosed herein include, but are not limited to, J. Ray McDermott, Inc. (New Orleans, Louisiana or Morgan City, Louisiana) and Kiewit Offshore Constructors, Ingleside (Corpus Christi, Texas).

Each unit may include one or more LNG storage tanks. Insulation in the tanks may be designed to limit LNG boil-off to approximately 0.1 % of the contained LNG volume per day. The capacity of a tank may be up to approximately 566,000 bbl (90,000 m³) of LNG. In some embodiments, the structure may include less than about 250,000 cubic meters of net LNG storage. In certain embodiments, the structure may include greater than about 50,000 cubic meters of net LNG storage. In certain embodiments, the structure may include greater than about 100,000 cubic meters of net LNG storage. The LNG capacity of a structure may be optimized based on a number of factors including LNG capacity of one or more LNG carriers, desired peak regasification capacity of the structure for converting LNG to a natural gas, the rate at which LNG from an LNG carrier is transferred from a carrier to one or more LNG storage tanks, and/or costs associated with operating the structure. Currently, carriers have a capacity of about 125,000 cubic meters to about 200,000 cubic meters. Peak natural gas production may be at least about 1 billion cubic feet per day (1,960 m³/h LNG). In certain embodiments, an optimal storage capacity of the structure may be about 180,000 cubic meters. FIG. 2 depicts an embodiment of optimizing the storage capacity of a structure.

In some embodiments, the LNG structure has a storage capacity of less than about 200,000 cubic meters of LNG. In some embodiments, the structure is configured to produce natural gas at a peak capacity of greater than about 1.2 billion cubic feet per day (2,400 m³/h LNG). In some embodiments, the LNG structure is configured to offload LNG from carriers having a storage capacity of greater than about 100,000 cubic meters. In some embodiments, the body of the structure has a length that is at least equal to a length required to provide sufficient berthing alongside the body for an LNG carrier having an LNG capacity of greater than about 100,000 cubic meters.

LNG tanks may substantially store vapor and liquefied natural gas. LNG tanks may be double containment systems. LNG storage tanks may include a liquid and gas tight primary tank constructed in a concrete interior of the structure. The primary tank may be formed from, for example, stainless steel, aluminum, and/or 9%-nickel steel. The LNG containment system may be, for example, a SPB (Self-supporting Prismatic shape IMO Type "B") rectangular tank system, a 9% nickel-steel cylindrical tank system, and/or a membrane tank system. LNG tanks may be freestanding tanks and/or self-supporting tanks. In an embodiment, each unit of the structure contains at least one steel membrane type LNG containment tank. The LNG tank may be cylindrical, rectangular, partially spherical, or irregularly shaped.

In an embodiment, migration of water within the concrete may be inhibited from reaching the inside of the tank using vapor barriers. Vapor barriers may be fitted on the internal faces of the tank. Structural elements, including containment walls and slabs, may be designed to meet the ULS

(Ultimate Limit State) criteria. Some exposed structural elements may be designed for fatigue and/or for accidental loads, such as boat impacts.

In some embodiments, the tank may be a membrane tank. Membrane tanks may be commercially available from, for example, Technigaz, Mitsubishi Heavy Industries, Inc., and Kawasaki Heavy Industries, Inc. In certain embodiments, tanks may be SPB (Self-supporting Prismatic shape IMO Type "B") tanks commercially available from Ishikawajima-Harima Heavy Industries Co., Ltd. (IHI) (Japan). The tank may be a commercially available 9% nickel cylindrical tank.

Water ingress through the concrete tank walls may cause freezing of the entrained water. Frozen water proximate the tanks may damage the containment system. Water ingress may cause damage to the polyurethane foam (PUF) insulation panels. Installation of an extensive heating system (e.g., electric) in the tank walls and slab may decrease the likelihood of freezing water proximate the tank. A temperature of concrete surfaces may be regulated to substantially inhibit icing on the surfaces of the concrete. A heating system may be provided on the walls and bottom to maintain a temperature of at least about 5°C. In some embodiments, a heating system is configured to maintain a temperature of the outer wall at or above about 5°C. Prestressing concrete walls may ensure water tightness of the concrete walls of the tank. A watertight coating on tank walls may inhibit water ingress. In certain embodiments, solid ballasting material may be maintained proximate the tank to avoid water proximate tank walls.

In certain embodiments, an LNG storage tank may include pre-tensioned concrete. The concrete tank may provide structural resistance to inner LNG and gas pressure loads and to outer hazards. The tank may include a primary barrier.

The primary barrier may be a stainless steel corrugated membrane. The stainless steel membrane may constitute a liquid and vapor tight inner containment. The tank may include a secondary barrier positioned between the primary barrier and the concrete. In an embodiment, PermaglassTM may form the secondary barrier. PermaglassTM may be a polyester/glass cloth composite. The secondary barrier may be incorporated in the insulating panels under the primary barrier. The secondary barrier may be incorporated in the insulation between the concrete structure and the primary barrier. The secondary barrier may retain liquid and vapor in case of a leakage of the primary barrier. The secondary liner may be applied on the entire bottom and wall surfaces of the tank. The secondary barrier should be insulated from the concrete support structure. The insulating structure may comprise the secondary barrier. The insulating structure may comprise insulating material.

In some embodiments, the main containment tank components may include, from the inside to the outside of the tank, the primary barrier, the secondary barrier, the insulating structure, the vapor barrier, and the concrete. The primary barrier may be the first line of protection against LNG leaks. In an embodiment, the primary barrier may be a corrugated membrane. The membrane may be stainless steel. An ammonia leak detection test may be performed on the membrane after it is erected. The secondary barrier may be PermaglassTM. In an embodiment, the insulating structure may be positioned outside the secondary barrier. The insulating structure may be coupled to the concrete walls and bottom. The insulated structure may be coupled with bonding mastic and/or studs. The vapor barrier may be applied to one or more faces of the concrete to mitigate water ingress. The concrete may form the outermost layer of the tank. Further

details regarding construction of LNG storage tanks are described in U.S. Patent No. 6,378,722 entitled "Watertight and Thermally Insulating Tank with Improved Longitudinal Solid Angles of Intersection" to Dhellemmes.

In some embodiments, one or more liquefied natural gas storage tanks may comprise: an outer wall; an insulating structure, wherein the insulating structure is positioned on an inner surface of the outer wall; a secondary barrier, wherein the secondary barrier is positioned on an inner surface of the insulating structure; and a primary barrier, wherein the primary barrier is configured to contain, or provide containment of, liquefied natural gas and/or vapor, and wherein the secondary barrier is configured to at least partially contain vapor and/or liquefied natural gas from leaking from the primary barrier. In some embodiments, the outer wall comprises concrete, the insulating structure comprises polyurethane foam, the secondary barrier comprises a polyester glass cloth composite, and the primary barrier comprises stainless steel.

In some embodiments, drainage systems, pressure monitors and regulators, nitrogen purge systems, and/or temperature monitoring systems may be positioned between tank components. The structure may include back-up monitors and regulators for temperature and/or pressure. The concrete may be equipped with a heating system to maintain a temperature of inner surfaces of concrete walls and slab. The temperature may be maintained such that water does not freeze proximate tank components. An Emergency Diesel Generator may be used to maintain a temperature of tank walls. In an embodiment, drainage systems remove water ingress. A piping network may be installed proximate the insulated space. The piping system may monitor and/or regulate conditions in the tank.

In some embodiments, tanks may be equipped with pump wells, suitable for send-out pumps. The pump wells may be supported from the structure roof. The brackets may be thermally isolated from the concrete structures. A filter box may be made around the bottom guide to prevent debris from entering the pump wells. The filter box may be removable. Pump pits may be provided on the bottom slab to achieve sufficient net positive suction head (NPSH) of the pumps without affecting overall tank height. Each pump well may have provisions for safe pump withdrawal/installation when the tank is in service, including a foot valve and nitrogen piping connection. In certain embodiments, LNG storage tanks may include pressure safety valves, vacuum relief valves, tank gauging, over-fill protection, roll-over prevention, leak detection, flammable gas detection, heat detection, settlement measurement systems, bottom slab and wall heating systems, cool-down sensors, temperature sensors for bottom and wall heating system, and/or lightning protection.

A purge/vent system may be positioned between the secondary liner and the concrete hull of the structure. The purge/vent system may include a nitrogen injection network that allows sweeping and purging of the secondary insulation space, as needed. In an embodiment, the primary and secondary insulation space may communicate at the top of the tank to maintain pressure equilibrium. A purge/vent pipe with outlet and a nozzle may be installed on the tank roof. Installation of the pipe and nozzle may allow complete purging of the inner tank and dome space. In some embodiments, a purge system may be positioned between the primary barrier and the secondary barrier where the purge system is configured to remove natural gas leaking through the primary barrier.

In some embodiments, LNG tanks may be equipped with automatic continuous tank level gauging, density monitoring, and density measuring. Each level indicator may have high and low alarms and will automatically stop in-tank pumps or unloading operations, as required. A temperature measurement system may be installed in the LNG tanks at various levels. Temperature of tank walls and/or slabs may be regulated to substantially prevent freezing in the event of any moisture ingress. Pressure transmitters may be provided in each tank to control the boil-off gas compressor, the vent system, alarms and to actuate the emergency shutdown system. Each tank may be protected against overpressure by safety valves. The tank pressure relief valves may release to atmosphere via a vent system. Natural gas from the pressure relief valves may be routed to the flare tower.

Cryogenic submerged pumps inside the tanks may transfer LNG from the storage tanks, via the re-condenser, to the suction of the LNG high-pressure send-out pumps. The LNG in-tank pumps may be high-volume, low-pressure pumps, and may provide sufficient net positive suction head (NPSH) for the deck mounted, high-pressure LNG pumps

Between LNG storage tanks and the outer walls and bottom of the structure, a grid of ballast storage areas may be used for ballasting. In some embodiments, ballast storage areas, also referred to as ballast cells, may be disposed throughout the structure. Ballast storage areas may be used to facilitate transportation to the site, and to ground and secure the structure to the seafloor. Ballast storage areas may be used to obtain sufficient on bottom weight. One or more ballast storage areas may be incorporated into the structure or body of the structure.

Ballast storage areas may be at least partially filled with solid and/or liquid ballast material. In some embodiments, water is used as a liquid ballast material. Sand may be used as solid ballast material. In some embodiments, a heavier material than sand may be used as solid ballasting material. Iron ore may be used as a solid ballasting material. Assuming a water-saturated density of solid ballast material is 3.0 t/m^3 , $78,400 \text{ m}^3$ of sand ballast may be replaced with approximately $40,000 \text{ m}^3$ of iron ore ballast. Water drainage and/or monitoring systems may be installed to monitor and regulate water ingress through the external walls of the ballast storage areas.

In some embodiments, construction errors may lead to water penetration during the design life of the terminal. In certain embodiments, to inhibit water penetration, ballast storage areas filled with solid ballast material or "dry ballast" are positioned next to the LNG storage tank. In an embodiment, sand may be placed in ballast storage areas next to tanks in order to achieve sufficient on-bottom weight for the structure. Solid ballast material in ballasts storage areas may maintain a dry condition to avoid water ingress into tank walls.

An embodiment of ballasting is depicted in FIG. 2. In some embodiments, side ballast storage areas 210, also referred to as outer ballast storage areas, and bottom ballast storage areas 215 may surround LNG tanks 110. Ballast storage areas 210 and 215 may provide additional on-bottom weight. Ballast storage areas 210 and 215 may increase a stability of the structure 100. In an embodiment, ballast storage areas 210 and 215 surrounding the tank 110 may be at least partially filled with a solid ballast material 220. Solid ballast material may be sand. In an embodiment, solid ballast material may be iron oxide. In an

embodiment, bottom ballast storage areas 215 positioned below a tank 110 may be filled with liquid ballast material 230 instead of solid ballast material 220. Liquid ballast material may include water. Using liquid ballast material may facilitate decommissioning. In some embodiments, ballast storage areas 210 and 215 may be filled with liquid ballast material. Since access to bottom ballast storage areas 215 may be difficult, utilizing liquid ballast material may be more desired than utilizing solid ballast material. Since access to side ballast storage areas 210 may not be as difficult, utilizing solid ballast material may be more desired than utilizing liquid ballast material.

The concrete slab and walls surrounding LNG storage tanks may be designed to substantially assure liquid tightness during the operational lifetime of the structure. Inspection of the inside of a concrete hull where an LNG storage tank, such as, but not limited to, a membrane tank, is located may not be feasible after installation of the tank. In certain embodiments, water levels in the ballast storage areas below a tank are maintained below the bottom of the tank slab. A water level in a ballast storage area positioned below a tank may be maintained at a height below the ceiling of the ballast cell, such that the freezing of water in the ballast does not occur proximate the tank. A drainage system may be installed. A water level monitoring system may be installed in the structure to maintain the water level.

In some embodiments, ballast storage areas are filled with water to provide a desired on bottom weight. After completion of water ballasting, dry ballasting may occur. In dry ballasting, the outer ballast storage areas are filled with sand ballast material, such that the apparent on bottom weight provides adequate foundation stability during the

operational lifetime of the structure. In certain embodiments, solid-ballasting operations may be carried out using a crane and conveyor system 202 mounted on a barge 204 moored alongside the structure (as depicted in FIG. 2). Sand may be obtained from the shore by shuttle barges. Alternatively, the bottom of a body of water may be dredged for solid ballast material.

After completion of the solid ballast operation, a permanent pump and drainage system may ensure that water levels in the solid ballast storage areas and/or in the water ballast storage areas underneath the LNG storage tank remain sufficiently low. Water in ballast storage areas may be maintained at levels such that the water does not freeze proximate a tank wall and/or slab. A water level of at least about 0.5 m below the exterior of the tank slab may be tolerated. Water levels may be monitored and/or regulated to substantially inhibit water contact with the LNG tank walls and/or slab during the lifetime of a structure. Maintaining the water level in ballast storage areas below the bottom of the tank may substantially inhibit long-term water ingress into the concrete tank walls and slab. Filling ballast storage areas below the LNG membrane tank and the peripheral ballast storage areas with water and then adding solid ballast material into the peripheral storage areas may accomplish water tightness and durability.

In some embodiments, the bottom part of tank walls 240 may be in contact with solid ballast material 220 instead of liquid ballast material 230. See FIG. 2. In an embodiment, solid ballast material may be placed in most ballast storage areas. Special drainage systems may be engineered to position dry solid ballast in most ballast storage areas. The floor 245 of the tank may be coated with a water barrier to protect the floor.

In some embodiments, the structure includes projections, also referred to as skirts, on a bottom surface of the body. The projections may at least partially project into a bottom of a body of water. Ballast storage areas may be filled such that the weight of the structure at least partially embeds at least a portion of the projections in the bottom of a body of water.

In some embodiments, projections 250 may at least partially form the foundation for the structure 100. See FIG. 2. The projections may provide at least some structural stability to the structure. Projections 250 may be positioned on a bottom surface 260 of the structure 100. The projections may be arranged in a repetitive grid of plane walls and slabs. Longitudinal and transverse projections located underneath the bottom surface of the structure may extend below the mudline in order to substantially achieve stability and/or inhibit the structure from sliding and overturning. The spacing and positioning of the projections may be such that the structure may be at least partially supported on the projections or skirts. Furthermore, the projections may be arranged to inhibit bowing of the structure while resting on the bottom of the body of water. In some embodiments, at least some of the projections are arranged in a grid pattern.

In some embodiments, under keel clearance may affect the design of the LNG structure. For example, an available channel depth may be about 13.7 m. The structure may be designed to maintain a specific under keel clearance in a predetermined channel. Channel depth may also affect draft of the structure. Lightweight concrete, semi-lightweight concrete, buoyancy caissons, and/or widening the structure base may be used to increase under keel clearance.

Soil erosion of a bottom of the body of water may be a concern. In an embodiment, the gap between both units of the structure may be substantially reduced after offshore installation to prevent substantial erosion of the bottom of a body of water between the units. Reducing the size of a gap between the two units of the structure may occur after the ballast operations of both units have been completed. In an embodiment, each unit is simultaneously ballasted and scour protection is installed around the structure.

An offshore LNG storage and receiving structure may be designed to receive liquefied natural gas from carriers and transfer the LNG to one or more LNG storage tanks. The LNG may then be vaporized in a heat exchange vaporization system. The vaporized natural gas may be sent out among several pipelines that distribute natural gas to other facilities for further processing and/or distribution.

The LNG storage tanks may contain vapor and liquefied natural gas. Natural gas vapor may form due to heat ingress into the storage tank. Heat may be introduced to the tank during ship unloading. Heat may enter the storage tanks from the LNG recirculation lines and by changes in the fluid composition when LNG is unloaded into the storage tanks. This vaporized LNG is typically referred to as boil-off gas ("BOG"). The normal BOG rate may be about 0.1 % per day of the total storage volume.

In some embodiments, BOG may be used to regulate the pressure in the LNG carrier while unloading. BOG may be used to regulate a pressure in LNG tanks. In certain embodiments, BOG may be compressed by a BOG compressor and routed to a condenser that recondenses BOG. In an embodiment, compressors may be centrifugal compressors. The recondensed BOG may mix with LNG inside the recondenser. The mixture may

be routed to the gasification trains. The recondenser may be designed to process all BOG generated in the structure. The recondenser may be designed to process vapor from unloading carriers. In some embodiments, one or more recondensers may be coupled to one or more LNG storage tanks. The recondensers may be configured to convert natural gas to LNG.

A pressure in the LNG tanks may be regulated by the operation of one or more BOG compressors. Vapor in the LNG tank may be pumped to a BOG compressor and returned to the LNG storage tanks. The compressed BOG may maintain a pressure in a tank. BOG compressors may operate to inhibit flaring during compressor maintenance. Vapor may be routed through a BOG header to the compressors.

BOG compressors may be designed to accommodate BOG from a carrier unloading during minimum send-out rate conditions. A vapor generation rate may not substantially increase during the life of the structure. As a rate of LNG send-out increases, the greater the structure may accommodate boil-off gas. At peak send-out rates, send-out gas may be recycled to tanks to maintain tank pressures. In certain embodiments, unloading may be delayed when a send-out rate is approximately zero. In an embodiment, LP (low pressure) pumps may pull a vacuum when send-out rates are high without recycling at least a part of send-out gas. In some embodiments, the use of a separate high-pressure reciprocating compressor to export boil-off gas directly to a pipeline during hurricanes is not justified when compared to the cost of flaring the limited amount of boil-off vapor expected during such a scenario. A compressor may be used to direct boil-off gas during severe weather to pipelines. Spare boil-off gas compressors may be installed. In some embodiments, one or more boil-off gas compressors may be coupled to one or more LNG storage tanks. The one or more

boil-off gas compressors may be configured to provide a source of compressed natural gas to the structure.

During hurricanes, the terminal may be abandoned and gas send-out will cease. All non-critical operations may be shut down and excess BOG may be flared rather than reprocessed. The recondenser may recondense at least a part of the BOG and provide sufficient pressure and surge volume at the suction of the high-pressure LNG send-out pumps. The main flow of LNG from the in-tank pumps may be routed directly to the recondenser. BOG may be recondensed by mixing it with a portion of cold LNG from the storage tanks.

In some embodiments, a recondenser may process BOG not returned to the LNG carrier. In an embodiment, the recondenser may be stainless steel. The internal vessel of the recondenser may not be inspected. In an embodiment, the recondenser vessel may be externally inspected.

In some embodiments, the recondenser may use subcooled LNG to condense BOG. The recondenser may be designed to at least partially recondense all BOG expected at maximum vapor generation rate, to provide adequate net positive suction head ("NPSH") to the pumps, to prevent cavitation and possible pump damage, and/or to provide sufficient residence time at peak LNG throughputs to control the recondenser. In certain embodiments, normal minimum sendout may be determined as the lowest total gas sendout (LNG+BOG) required to recondense all BOG during ship unloading. In an embodiment, a recondenser bypass may be used to accommodate higher than expected LNG sendout rates. The bypass may send BOG to flare or vent systems.

In some embodiments, incomplete condensation of BOG may increase the pressure of the vapor space in the condenser. The liquid level may then decrease and more contact area for condensation may be created (and vice versa). If the

pressure in the vapor space is too high (e.g., a blocked recondenser outlet causes pressure build up), a pressure controller may open a control valve to bleed excess gas to the flare. When incoming BOG flow to the recondenser is interrupted (e.g., low LNG tank pressure stops the compressor), the output signal from the ratio controller may be zero. When the output signal is zero, the packing area may be completely bypassed. To prevent the recondenser from becoming completely liquid-full (e.g., from continued condensation of the remaining BOG in the recondenser), the level controller may open the level control valve to inject 'padding' gas from the natural gas send-out line. Natural gas from the send-out line may compensate for restricted BOG flow. Failure of the bottom pressure control loop or a blocked recondenser outlet may cause a high liquid level in the LNG storage tank and a high pressure in the vapor space. To inhibit an excessive increase of the vapor space pressure, a pressure controller may override the output of the level controller and vent or flare excess vapor.

During the production of natural gas, high-pressure pumps may transfer LNG from the tanks to one or more heat exchangers, also referred to as heaters or vaporizers. LNG may be vaporized at high pressures in the heat exchangers. In one embodiment, the heat exchanger is an open rack vaporizer. In another embodiment, the heat exchanger is a submerged combustion vaporizer. LNG may be fed through aluminum tubes. A heating medium may flow from the top of the vaporizers over the tubes, whereby vaporization occurs. The temperature drop across the heat exchanger of the heating medium may be less than or equal to about 10°C (18°F).

Seawater may be used as the heating medium for one or more heat exchangers. The heat exchangers may use water from the body of water the structure is positioned in to vaporize

LNG in a once-through configuration. Water lift pumps may deliver water to the heat exchangers from a water intake system. Intake screens, velocity, location, and/or orientation may be selected to minimize marine life entrainment and impingement. The water may be treated to minimize marine growth within the water intake system. The water intake system may discharge water at an outlet structure. A water intake and outlet system may be installed to circulate the required volume of water from the body of water, through the facilities on the structure deck, and back to the body of water.

FIG. 3 depicts an embodiment of a water intake system. The water intake 310 and outlet 320 structures may be at least partially positioned on a bottom of a body of water. The inlet structures 310 may be positioned relatively close to the structure 100 and outside strong concentrations of currents and waves. One or more outlets 320 of the water intake system may extend from the structure 100. The outlets 320 may not be located proximate the structure 100.

An outlet conduit 330 may extend from the structure 100 and release water away from water inlet 310. The outlet 320 may include vertical diffusers 340. The flow rate at the outlet may be relatively low. Scour protection 350 may be positioned proximate outlet bends and/or connections to the bottom of a body of water.

Scour protection 350 may be positioned proximate the inlets 310, the outlets 320, the structure 100, and/or between the units 180, 190 to inhibit erosion. Scour protection along the structure may extend beyond the location of the outlet pipeline to minimize the development of holes and/or imposed deformations.

Additional bends in the inlet 310 and/or outlet line may be included at the interface of a buried section of the

inlet/outlet and a section running over the scour protection 350 to accommodate differential settlement. In an embodiment, concrete ballast mattresses may couple the water intake conduit to the sea floor. Scour protection may be applied proximate the concrete mattress to inhibit erosion of the ballast mattress. Water conduit may be routed from one or more water inlets to the vaporization equipment located on an upper surface of the structure and then routed from the vaporization equipment to one or more water outlets.

In some embodiments, the same scour protection 350 may be used for the long sides 360 of the structure 100 and the inlet structures 310. In an embodiment, a gabion mattress is not installed at the outlets. A standard scour protection may be applied at the one or more outlets. In an embodiment, standard scour protection may include 60-300 kg rocks (0.5 m thick) upon a filter layer of either geotextile or gravel.

The water intake system may include equipment (e.g., pumps) that provides water to the heat exchangers; fixed hardware that channels water from the body of water, through the vaporization system, and back to the body of water, such as the ocean, again; pump chambers, from which water may be pumped to heat exchangers; and water inlets and outlets off the structure. The water intake system may be designed to have redundancy. In an embodiment, two or more water inlets may be used. In this manner if one inlet is offline, another inlet may provide water to the structure. In an embodiment, the outlet system may include only one outlet. Water may flow over a side of the deck if the outlet is offline. The water inlet may comprise a water inlet conduit comprising a water receiving end and a water dispensing end.

FIG. 4 and FIG. 8 depict embodiments of a water inlet 310 positioned on a vertical wall 400 of the structure 100. Water inlets may be positioned directly on the surface of the

structure. A water inlet 310 may be positioned on a surface of the structure 100 below a water level of a body of water. In some embodiments, a water inlet 310 may be designed such that reflections of waves impacting the structure (e.g., standing waves) do not substantially affect the flow of water in the intake system. A water inlet 310 may reduce the effect standing waves on a water level in one or more containment regions 410, also referred to as water-receiving chambers.

Baffles may be positioned in openings in the inlet 310 and/or water receiving chambers. In some embodiments, baffles may reduce the effect of wave reflections against the structure and/or on water levels in containment regions and/or the flow in water intake systems. FIG. 8 depicts an embodiment of baffles 415 in an area below water receiving chamber 410. Baffles may reduce the risk of pumps cavitating when a standing wave pulls water from a chamber. In an embodiment, baffles may separate a first water-receiving chamber from a second water-receiving chamber. The level in the second water-receiving chamber may not rapidly change due to the baffles. Maintaining water in the second water-receiving chamber may prevent pump cavitation. Pumps 420 may transfer water from a water-receiving chamber 410 to a heat exchanger or other process equipment. In some embodiments, one or more baffles may be coupled to one or more water inlets. The one or more baffles may reduce the effects of waves on the water entering the one or more water inlets. In some embodiments, one or more baffles may be coupled to a second water-receiving chamber. The one or more baffles may reduce the effects of waves on the water entering the second water-receiving chamber.

In an embodiment, screens 430 may be positioned in inlet 310 and/or water receiving chamber 410 to inhibit impingement

or ingress of marine life. A crane 440 positioned on the structure 100 may facilitate maintenance of the water intake system (e.g., removing screens and/or baffles for maintenance or repair). In an embodiment, the crane 440 may be positioned on an elevated top surface 450 of the structure 100.

Screens may be aquatic filter barriers as described in U.S. Patent Application No. 10/153,295, published as US 2003/0010704 A1, entitled "COOLING MAKEUP WATER INTAKE CARTRIDGE FILTER FOR INDUSTRY" to Claypoole et al. Aquatic filter barriers may include sheets of fine polyethylene/polypropylene mesh fabric.

In some embodiments, wedge wire screens commercially available from Johnson Screens may be used. Wedge wire screens may be cylindrical filters made by winding wire around cylindrical support rods and forming a series of gaps between the wires.

Water from the water intake systems may flow to a heat exchanger vaporization system. Heat exchangers may be used to vaporize LNG received from LNG carriers. In some embodiments, LNG from one or more storage tanks may flow to one or more heat exchangers. The vaporized natural gas may be provided to one or more commercially available pipelines coupled to the LNG structure.

In certain embodiments, open rack vaporizers vaporize LNG. In some embodiments, submerged combustion vaporizers vaporize LNG. LNG may be pumped upwards through a parallel set of tubes, for example, a parallel, horizontal set of tubes, while water runs downward through the exterior of the tubes by gravity. The heat from the water may regassify the LNG. Heat transfer efficiency may be improved using fins. Fins may be positioned on the outer surfaces of the tubes, the inner surfaces of the tubes, and/or the inner surfaces of

the outer shell. Water may be sprayed and/or cascaded on the tubes. Using a short inner tube at the LNG inlet of the tube bank to extend the initial heat transfer rate over a greater length of the tube, may reduce the chance of ice formation at the point where LNG enters the heat exchanger. In an embodiment, the operating pressure of the heat exchanger may rise and fall according to the pump curve of the HP (high pressure) pump.

In some embodiments, LNG may be vaporized as schematically illustrated in FIG. 5. Heat exchangers 610 may be open rack vaporizers. Heat exchangers 610 may be submerged combustion vaporizers. In an embodiment, open rack vaporizers may be a cost-effective heat exchanger option. Water may be transferred from the water inlet 310 to the heat exchangers 610 to vaporize LNG. Water may then be released back into the body of water through the water outlet 320. LNG from a carrier 620 may be transferred to one or more storage tanks 110 via unloading arms 630. Some LNG may vaporize during unloading from a carrier 620. Some LNG may vaporize in the storage tanks 110. The vaporized LNG may be called boil-off gas ("BOG").

Some BOG may be returned to the carrier 620 through one or more unloading arms 630. Returning BOG to the carrier 620 may be part of a vapor balance system. In addition to, or in lieu of, passing BOG to the carrier 620, BOG may also be compressed in a BOG compressor 640. The BOG may pass through a BOG compressor scrubber 635 before transfer to the BOG compressor 640. The BOG may pass through a BOG desuperheater (not shown) before entering the BOG compressor scrubber 635. Compressed BOG may be recondensed in a recondenser 650 and returned (not shown) to storage tanks 110 and/or transferred to a heat exchangers 610. While not shown, in some embodiments compressed BOG and/or recondensed BOG, from the

BOG desuperheater, BOG compressor scrubber 635, BOG compressor 640 and/or recondenser 650, may be transferred back to storage tanks 110 through separate drain lines and/or through valving and flow control of existing lines.

LNG may be pumped from storage tanks 110 to heat exchangers 610 to be vaporized. In some embodiments, LNG may be pumped, utilizing low pressure pumps (not shown) that may be in storage tanks 110, to recondenser 650 and then, utilizing pumps 655, preferably high pressure pumps, the LNG may be pumped to heat exchangers 610.

Vaporized LNG may be warmed in a heater 660 to inhibit hydrate formation. The heater 660 may use waste heat 670 to warm natural gas. Natural gas may enter export metering lines 680. Natural gas may be distributed from the export metering lines 680 to commercially available pipelines 690 coupled to the structure. Some natural gas may be used as fuel 700 on the structure. In some embodiments, vaporization equipment may be coupled to an upper surface of the body. The vaporization equipment may be configured to vaporize the LNG to natural gas during use. A water intake system may be configured to draw water from a body of water and supply water to the vaporization equipment.

The amount of water flow required in the heat exchanger is related to the selected temperature drop across the heat exchanger. The amount of cold energy or cold thermal inertia returned to the sea may be the same if a smaller amount of water is returned at a lower temperature or a higher flowrate is returned at a slightly warmer temperature. In some embodiments, a larger temperature drop across the heat exchanger may cause ice formation in the water intake system. Smaller temperature drops across the heat exchanger for the water may be possible. In certain embodiments, warmer sea

temperatures may permit a higher temperature drop across the heat exchanger and reduce the water flowrate.

An outlet may be positioned at least approximately 500 meters from an inlet. In certain embodiments, outlets and inlets may be separated such that cold water from the outlets does not substantially mix with ambient water proximate the inlets. Outlets may be positioned at a distance from the structure to accommodate a working boat and/or platform alongside the structure.

In some embodiments, no spare water outlet system may be constructed. A spare outlet system may not be required. If the water outlet system breaks down, water may be temporarily run directly over an edge of the structure. In an embodiment, a sluice gate may be opened below water level to release water from the structure if the water outlet system is offline.

In certain embodiments, flow controllers may regulate the natural gas send-out flow rates from the heat exchangers, also referred to as heaters or vaporizers. Flow controllers may include a flow transmitter on the heat exchanger outlet and a control valve on the vaporizer inlet. If the gas outlet temperature or seawater exit temperature becomes excessively cold, the flow controller may be overridden. Regasification and send-out equipment may be designed for an average throughput of natural gas. In an embodiment, regasification and send-out equipment may be designed for an average throughput of about 7.7 million ton per annum (mtpa) and a peak factor of about 1.2 billion cubic feet per day (2,400 m³/h LNG).

In some embodiments, the structure may be designed to vaporize LNG delivered by LNG carriers and export natural gas into the existing pipeline network. The structure may have a capacity to offload and regassify at a peak export rate of

about 1.2 bscf/day (2,400 m³/h LNG) to the gas network. The structure may be designed to have a nominal regassification rate of about 1.0 bscf/day (1,960 m³/h LNG). In an embodiment, the structure may be designed such that the peak regassification rate is expandable. The structure may have a peak sendout rate of about 1.8 bscf/day (3,600 m³/h LNG).

Natural gas exiting the heat exchangers may be metered into pipelines and flow to tie-in locations onshore. The reduction in pressure along the pipelines may produce a cooling effect. The cooling effect may only be partly compensated by heat ingress from the surrounding seawater. The send-out gas may be heated in order to mitigate the possibility of hydrate formation in the takeaway pipelines. In certain embodiments, as the gas enters the existing wet associated gas pipelines, it must be above about 21.1°C (70°F) to avoid hydrate formation. A spare sales gas heater may be installed to heat the send out gas. In an embodiment, demineralized hot water may heat send-out gas. The natural gas stream may be divided between the pipelines connected to the structure. In an embodiment, each pipeline may have its own pressure reduction station and two or more 10-inch ultrasonic custody transfer meters to accommodate the export flow rate.

In some embodiments, the structure may comprise an export metering system disposed on the body of the structure and coupled to the vaporization equipment. The export metering system may be configured to monitor the flow of produced natural gas from the structure to an on-shore location. In some embodiments, the structure may comprise a plurality of natural gas transfer pipelines coupled to the vaporization equipment. Each of the pipelines may be coupled to a separate on-shore natural gas pipeline system. Control of the transfer of natural gas through each of the

pipelines may be performed using one or more controllers on the structure.

The gas from all the heat exchangers may be combined in one or more common sales gas headers. The natural gas exiting the heat exchangers may vary in temperature according to the LNG throughput and the seawater temperature. In an embodiment, the send-out gas exit temperature from the heat exchangers may be about 1°C to about 22°C. The sendout gas from the structure must be in excess of about 35°C (at the maximum pressure of 86 bar (gauge) upstream of the flow control valves) to prevent hydrate formation where the natural gas export lines tie into the wet associated gas pipelines. In an embodiment a maximum gas export temperature may be about 49°C. Gas export temperatures may be regulated by applicable codes. Gas temperature may be controlled using a hot water bypass control loop.

In some embodiments, a structure may include a relief system. The relief system may include relief headers, lit flare headers, and/or emergency vent headers (low pressure and high pressure vents). Flare headers connected to the tank vapor space, balance line, and/or depressuring lines may operate during tank cool down, overpressure scenarios, and/or in hurricane situations where the structure will be de-manned and the vaporization process stopped. In an embodiment, a self-igniting flare may be provided to safely dispose of emergency hydrocarbon releases. A majority of the process relief valves may be routed to the flare. The flare system may detect a release of emissions and self-ignite when required. The ignitable flare concept may minimize the overall greenhouse gas emissions to the atmosphere by the flare. In an embodiment, under normal operating conditions, the flare system may rarely flare. BOG may be recondensed to LNG and routed to high-pressure

LNG pumps. The vent stack may be located on the structure. Vents may be connected to the atmosphere. An emergency vent header may include tank pressure relief valves. The vent stack may be designed to accommodate all relief loads from the tank and/or may be used during flare maintenance.

An offshore LNG receiving and storage structure may accommodate LNG storage tanks, allow LNG vaporization plant and other process equipment and utilities to be positioned on the upper surface of the structure, and safely enable LNG carriers to berth directly alongside the structure. An embodiment of the LNG structure is depicted in FIG. 6. The structure 100 may include a first upper surface 710 with LNG transfer equipment 320. The structure 100 may also include a second upper surface 720 below the first upper surface 710. The second upper surface 720 may include docking equipment 730. Docking equipment 730 may couple a liquefied natural gas carrier 740 with the structure 100. The structure 100 may allow a carrier 740 to dock on one or more sides of the structure. In an embodiment, docking equipment 730 may be positioned on both lateral sides of the structure 100, in an embodiment. A "buffer belt" around a periphery of a LNG tank may provide protection for the tank against carrier impact.

The top slab level of the structure 100 may be determined by structural stiffness requirements and consideration of the LNG tank 110 dimensions. Topsides 750 of the structure 100 may be constructed and/or integrated in a dry dock prior to positioning the structure in a body of water. In an embodiment, the structure topsides 750 may be elevated on about 5m high steel module support frames 760. Structure topsides 750 may be elevated for ease of construction. Elevating the topsides 750 of the structure 100 may also allow water to run over the deck 710 under severe weather conditions without substantially submerging

equipment, such as heat exchangers 610 and LNG transfer equipment 320, on the topsides. Structure topsides may be elevated for ease of construction.

The structure may be designed to accommodate severe weather conditions such as hurricanes, tropical depressions, tsunamis, tidal waves, and/or electrical storms. During severe weather conditions, large waves may impact the structure and green water may flow over a deck of the structure. At least about one meter of water present on a horizontal face of the structure may be classified as "green water". In certain embodiments, the degree a wave overtops a surface of the structure may be substantially reduced. Raising the structure deck level 710, constructing a wave wall, constructing a wave deflector 770, and/or raising topsides 750 on steel modules 760 above green water may decrease the risk of damage to the structure 100 by overtopping waves.

The structures may additionally include steel modules that raise the topsides equipment above the deck level. Modules may be positioned at a height above the deck to reduce damage from overtopping waves and/or green water. Excessive wave run-up and passage of green water onto the terminal deck during hurricane conditions may be minimized by the installation of a curved steel wave deflector along one or more exposed sides of the structure.

In some embodiments, the structure may include docking, also referred to as mooring, equipment on one or more sides of the structure. The structure may include one dock. Berthing facilities, dolphins, fenders, and/or cryogenic unloading arms may allow bi-directional berthing of carriers directly alongside the structure. Approximately 15% of the time, the predominant current switches directions (e.g., a southwest current may switch to a northeast current).

Allowing a carrier to berth in either direction (i.e., bi-directional berthing) may increase the efficiency of the structure.

In some embodiments, the structure may be positioned substantially parallel to the direction of the predominant current. Ship-shore interfaces may be such that carriers can berth and offload directly alongside the structure. In an embodiment, docking directly on the structure may avoid the construction of separate berthing and offloading structures. A structure may be configured to allow a carrier to approach the structure without substantially damaging the structure. An LNG carrier may approach the structure with the help of one or more tugboats.

In an embodiment, an LNG carrier may dock such that the structure substantially protects the carrier from waves. The structure may be configured to provide a breakwater length for a carrier. When a carrier docks directly on the structure, the carrier may be at least partially protected from waves that impact the structure rather than the carrier. In certain embodiments, units may be positioned in order to provide adequate breakwater length for LNG carriers.

In some embodiments, the structure may be constructed in a graving dock location prior to towing and/or floating the structure to a desired location for operation. A purpose-built graving dock may be created to build the structure. In some embodiments, the units may be constructed in parallel in a purpose-built dry dock. After construction, the structure may be towed out of the graving yard and positioned in the body of water.

An LNG carrier may be berthed directly on the structure. The structure may be oriented in the substantially same direction as the predominant current. In some embodiments, the berthing may occur some distance from the structure using

berthing dolphins. The structure may be configured to have a breakwater function for carriers docked directly on the structure. In certain embodiments, the structure may include docking equipment configured to allow carriers to dock directly on the structure. The structure 100 may include a first surface 710 where process equipment 610 is located, as depicted in FIG. 6. The structure 100 may have a second surface 720, below the first surface 710, configured to ease docking with a carrier 740. The second surface 720 may be at a height similar to the carrier 740. Docking equipment 320 may be positioned on the second surface 720.

In some embodiments, the first and second upper surfaces are above the surface of a body of water. The height of the second upper surface above the surface of the body of water may be such that an angle of mooring lines extending from the docking equipment to the liquefied natural gas carrier coupled to the body is less than about 30 degrees. In some embodiments, one or more fenders may be positioned about a perimeter of the body. The one or more fenders may be configured to absorb a substantial portion of a load from an LNG carrier colliding with the one or more fenders. In some embodiments, the structure may be positioned in a body of water such that the longitudinal axis of the structure is substantially aligned with the predominant current direction. In some embodiments, the body has a length that is at least equal to a length required to provide sufficient berthing alongside the body for a liquefied natural gas carrier having a liquefied natural gas capacity of greater than about 100,000 cubic meters.

In some embodiments, one or more docking platforms may be positioned in the body of water proximate to the body. The one or more docking platforms may comprise docking equipment. The one or more docking platforms may be

positioned in the body of water such that liquefied natural gas carriers can dock with the body in different orientations. In some embodiments, the docking equipment may be positioned on the body such that an angle of mooring lines extending from the docking equipment to the liquefied natural gas carrier coupled to the body is less than about 30 degrees.

Structure 100 may include an unloading platform 880, depicted in FIG. 6. The unloading platform 880 elevation may be at a predetermined height 890 above a top surface of the body of water. The unloading platform may be made of concrete. An edge of the platform may protrude over the side of the structure. The unloading platform 880 may support LNG transfer equipment 320. The LNG transfer equipment 320 may offload LNG from an LNG carrier 740.

The LNG transfer equipment 320 may include unloading arms 900, also referred to as loading arms. Unloading arms may be Chiksan unloading arms available from FMC Energy Systems. The LNG transfer equipment may include power packs, controls, piping and piping manifolds, protection for the piping from mechanical damage, ship/shore access gangway with an operation cubicle, gas detection, fire detection, telecommunications capabilities, space for maintenance, Emergency Release Systems (ERS), Quick Connect / Disconnect Couplers (QCDC), monitoring systems, and/or drainage systems.

In some embodiments, LNG may be transferred from an LNG carrier to the LNG storage tanks by means of one or more unloading arms, for example, but not limited to, swivel joint unloading arms. The unloading arms may be used for unloading the LNG. One or more unloading arms may be used for returning vapor displaced in the storage tanks back to an LNG carrier. In an embodiment, unloading arms may be used for either liquid or vapor service, as required, allowing

maintenance of any of the unloading arms. Between unloading operations, the unloading system may be kept cold by re-circulation of a small quantity of LNG.

The LNG unloading arms 900, depicted in FIG. 6, may include a fixed vertical riser 910 and two mobile sections, the inboard arm 920 and the outboard arm 930. A flange 940 for connection to a carrier 740 may be positioned proximate an end of the outboard arm 930. Swivel joints may enable the arms and the connecting flange to move freely in all directions. The length of the unloading arm may be designed to accommodate different LNG carrier sizes. Unloading arm length may accommodate the elevation change between a fully laden and an empty LNG carrier, the movement of the ship due to tides and longitudinal and transfer drift, and the elevation of the structure. In an embodiment, the design of an unloading arm may be optimized. A length of an unloading arm may be optimized. Unloading arms may be located proximate a center of the structure. In some embodiments, there may be one or more fixed vertical risers and mobile sections depending on the number of LNG unloading arms.

Unloading arms may be equipped with an emergency release system. When the connecting flange reaches the limit of its operating envelope, an alarm may sound, the cargo pumps may shut down, and the unloading arm valves may close. Automatic disconnection of the unloading arms from the ship manifold may then occur. The arms will normally be operated from a control panel in a cabinet or control room located on the structure (see 950 in FIG. 6) proximate the arms.

Commonly available, traditional, hard unloading arms may be used. The maximum allowable pressure drop and the liquid velocity restrictions related to unloading arm vibration and cavitation may determine a minimum unloading arm diameter. The number of unloading arms positioned on the structure may

be the number necessary to provide a desired maximum liquid loading rate. A vapor return unloading arm may be used to return BOG from the carrier during unloading. An extra unloading arm may be positioned on the structure for use as an unloading arm or a vapor return for ease of maintenance and/or repair. In an embodiment, an unloading rate may be reduced to approximately 50% to 60% of the design capacity when one or more unloading arms are being repaired or replaced. In some embodiments, the LNG may be recirculated through unloading arms to regulate temperature when the unloading arms are not in operation. When unloading is substantially complete, nitrogen gas may be used to force LNG from the unloading arms back into the carrier and into the storage tanks via drain lines. In an embodiment, a piping layout may be sloped to allow LNG to drain into the storage tanks without the use of a drain drum. In some embodiments, one or more unloading arms may be purged with nitrogen after unloading liquefied natural gas from a carrier.

Although a three-unloading arm concept may be technically acceptable, a four-unloading arm concept may have more redundancy. Redundancy may increase the integrity and/or reliability level. The spare unloading arm may be used on a day-to-day basis. This may safeguard the proper functioning of the equipment. Therefore, the installation of one or more spare unloading arms may increase the normal overall LNG loading capacity.

The design of the structure may account for severe weather conditions. To decrease the environmental impact on the slender and flexible unloading arms, the unloading arms may be put in "hurricane resting position" when hurricane conditions are expected. In hurricane resting position, the unloading arm riser may remain vertical but the inner and outer arm will be tied-back horizontally. In some

embodiments, a support frame may be positioned behind unloading arms, to secure the horizontal part of the unloading arm by an extra fixation point. In some embodiments, at least a portion of the unloading arms may be positioned in a substantially horizontal position during storage of the unloading arms.

In some embodiments, LNG may be unloaded through an unloading line and recirculation line. Once the unloading arms have been sufficiently cooled, an LNG pumping rate may be gradually increased until the design flow is attained. A high unloading rate may facilitate a quick turnaround time of the LNG carriers and provide operational flexibility. The unloading arm package may consist of three reduced-bore liquid unloading arms and one vapor return arm. One of the liquid arms may be a hybrid design to allow vapor return, in the event of vapor arm maintenance. In an embodiment, during the periods between offloading LNG carriers, a small side-stream of LNG may be recirculated through the recirculation line to the unloading manifold to maintain cryogenic pipework temperatures. Regulating a temperature of the unloading arm may reduce the time required for pipework cooldown during unloading.

The tank operating pressure during the unloading operation may rise to minimize vapor generation due to heat ingress. The vapor displaced during the unloading process may be returned to the LNG carrier using the pressure differential between the storage tanks and the carrier. A return gas blower may not be required due to the short tank to carrier distance, in some embodiments.

The unloading pipework may slope continuously down to the tanks. In an embodiment, the unloading piping system may continuously slope down to at least one tank. Sloping the pipelines towards the tanks may eliminate a need for a

'Jetty' drain drum and associated lines. Pressure control may be used to maintain the LNG unloading line under pressure and to control the unloading flow. Regulation of the pressure may be necessary to prevent tank overpressure and/or vibration within the unloading line.

In some embodiments, a significant topside inventory of LNG on the structure may be held in the recondenser vessel and pump suction header. The recondenser and HP pump suction header may remain liquid-full during normal plant operation. In the event of zero sendout from the structure (e.g. hurricane scenario), the recondenser vessel and the header may remain liquid full to allow the line to remain at cryogenic temperatures. In the event of an emergency situation, (e.g. direct hurricane impact on structure or fire on the structure), an emergency function to drain the recondenser and suction line may be provided. Drainage of the system may be by gravity flow back into the tank underneath the recondenser. Residual pressure within the system may at least partially assist the gravity flow back to the tanks. After drainage, the remaining LNG inventory within the process equipment may be insignificant.

The structure may include one or more emergency safety systems. In an embodiment, emergency safety systems may be designed to comply with acceptable industry codes. During operation of the emergency system, several structure operations may be shut down. The LNG unloading operation may cease in a quick, safe, and controlled manner by closing the isolation valves on the unloading and tank fill lines and stopping the cargo pumps of the LNG carrier. The emergency operations may be controlled on the LNG carrier or from the structure via a ship-to-shore interface. Emergency controls may be manual (e.g., buttons in strategic locations), automatically (via the appropriate alarms signals received

from the transfer facilities), or by rupture of the ship-to-shore link. Emergency systems may be designed to allow LNG transfer to be restarted with minimum delay after corrective action has been taken.

The second stage emergency shutdown system may activate the unloading arm emergency release system (ERS) and cause the unloading arms to disconnect from the ship. "Dry break" uncoupling may be achieved by ensuring the closure of two isolation valves, one directly upstream and one directly downstream of the emergency release coupler prior to the uncoupling action. In some embodiments, unloading arm uncoupling may occur as quickly as possible. As the piping systems for the LNG carrier and the structure are relatively short, loading arm ERS valve closure times of 5 seconds may not give rise to surge pressures exceeding the design pressure of the piping systems.

The export shutdown may be activated by manual initiation. The emergency system may stop and isolate all pumps and compressors, isolate the heat exchangers and superheaters, and/or close various valves. Activation of the export shutdown, ERS, may stop and isolate the gas export equipment in a safe, sequential manner. The emergency system may initiate draining of the LP pump send-out header, recondenser, and HP pump suction header back into the storage tanks to minimize the inventory of LNG above deck level.

C L A I M S

1. A liquefied natural gas storage structure positioned in a body of water comprising:
 - a body;
 - a liquefied natural gas storage tank contained within the body;
 - wherein at least a portion of a bottom surface of the body rests upon a portion of a bottom of the body of water.
2. The structure of claim 1, further comprising liquefied natural gas transfer equipment.
3. The structure of claim 2, wherein the liquefied natural gas transfer equipment is configured to transfer liquefied natural gas from a liquefied natural gas carrier to the liquefied natural gas storage tank.
4. The structure of claim 2, wherein the liquefied natural gas transfer equipment comprises an unloading arm.
5. The structure of claim 4, wherein the unloading arm is coupled to the liquefied natural gas storage tank.
6. The structure of claim 1, wherein the liquefied natural gas storage tank comprises:
 - an outer wall;
 - an insulating structure, wherein the insulating structure is positioned on an inner surface of the outer wall;
 - a secondary barrier, wherein the secondary barrier is positioned on an inner surface of the insulating structure; and
 - a primary barrier, wherein the primary barrier is configured to contain liquefied natural gas.

7. The structure of claim 4, wherein the unloading arm is coupled to the liquefied natural gas storage tank with a conduit.
8. The structure of claim 7, wherein the conduit is arranged in a continuously sloping layout.
9. The structure of claim 2, wherein the liquefied natural gas transfer equipment comprises an unloading arm coupled to the liquefied natural gas storage tank with a conduit arranged in a continuously sloping layout.
10. A method of using a liquefied natural gas storage structure as described in any one of claims 1 to 9 in a body of water comprising:
 - receiving liquefied natural gas from a liquefied natural gas carrier;
 - storing the liquefied natural gas in a liquefied natural gas storage tank; and
 - processing the liquefied natural gas to natural gas using vaporization equipment.

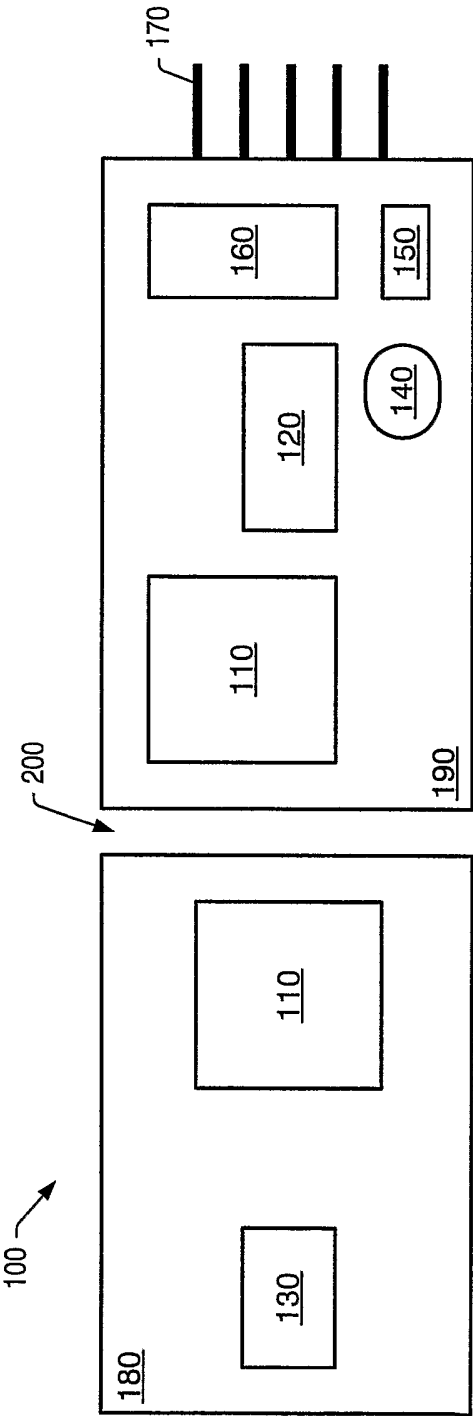


FIG. 1

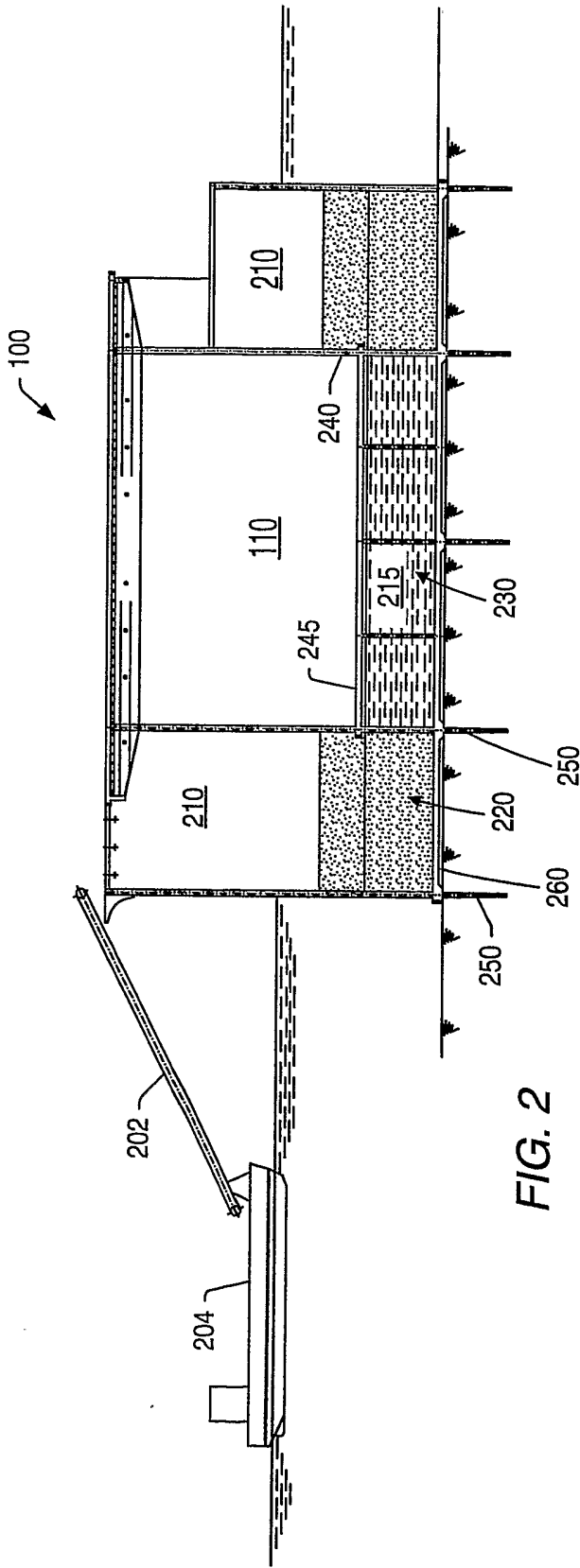
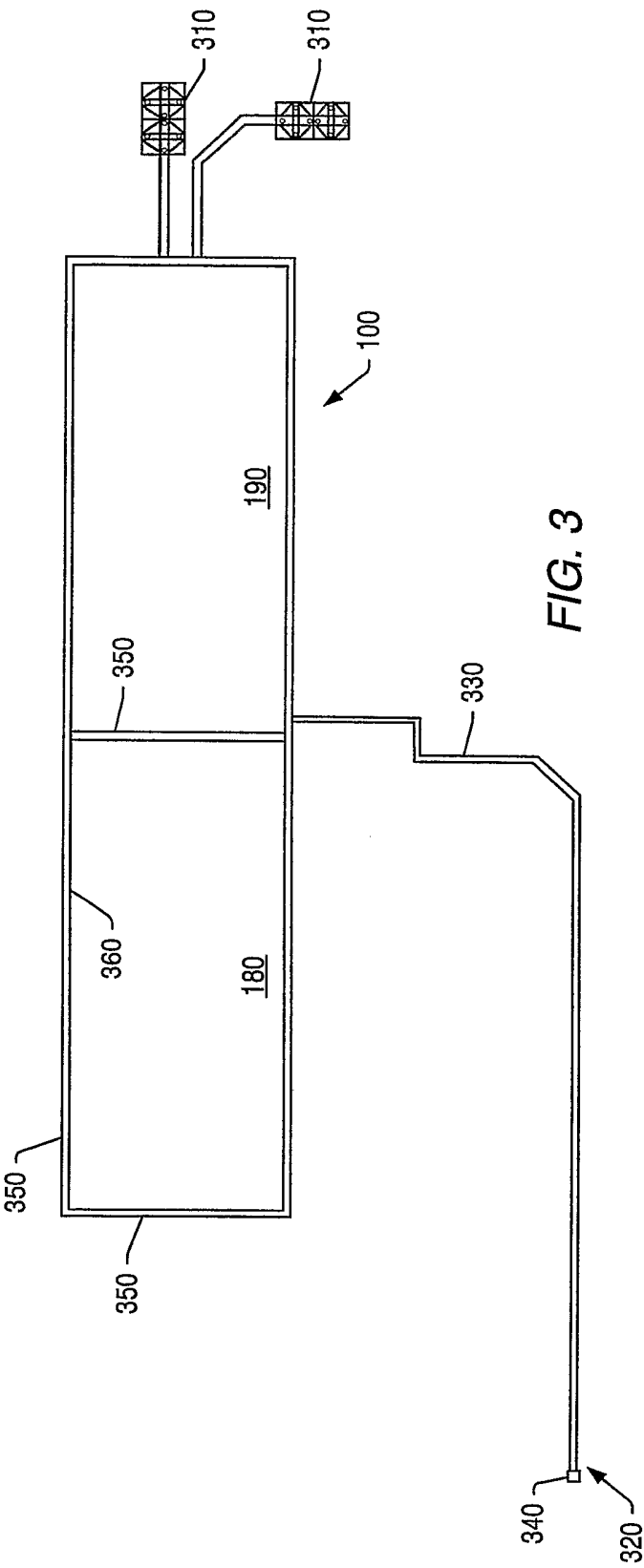


FIG. 2

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4 / 8

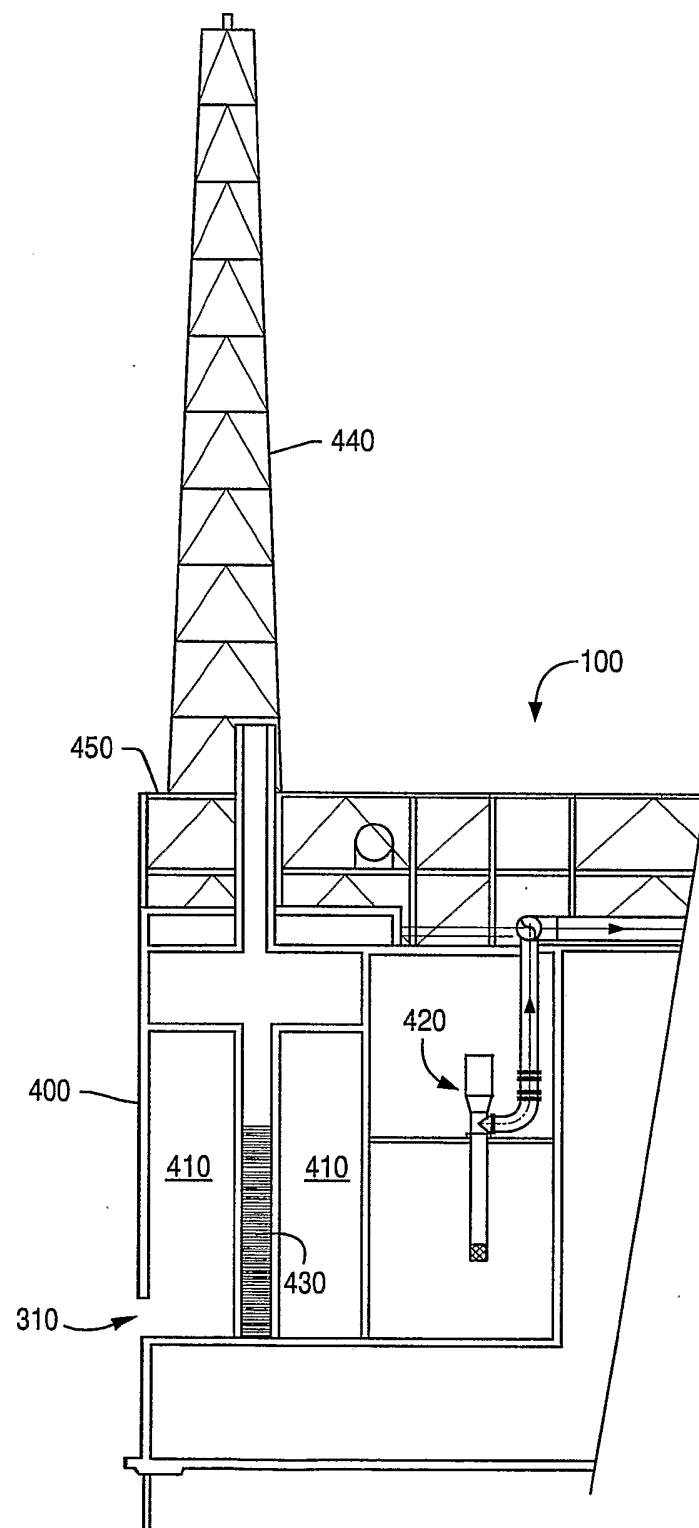


FIG. 4

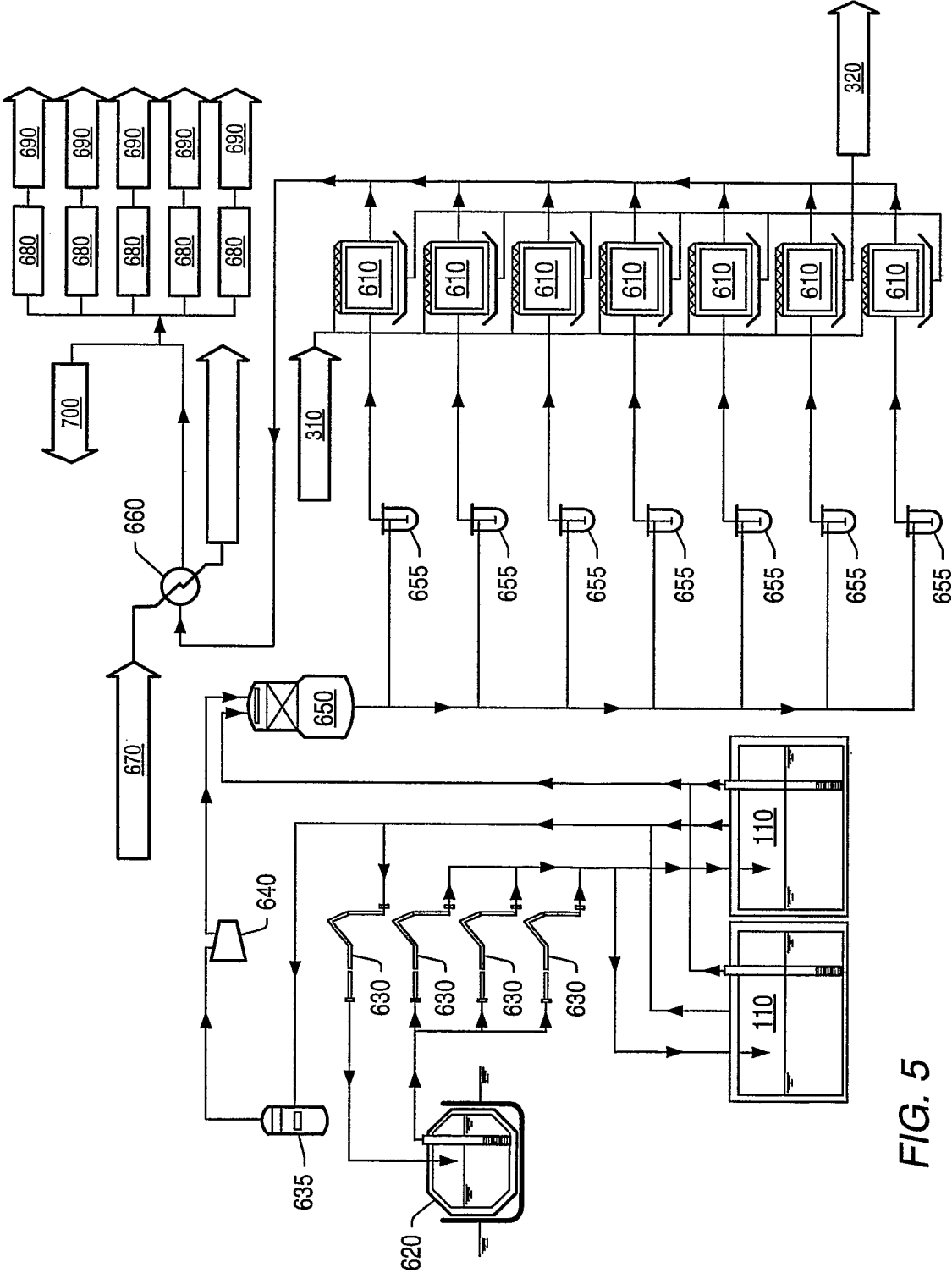


FIG. 5

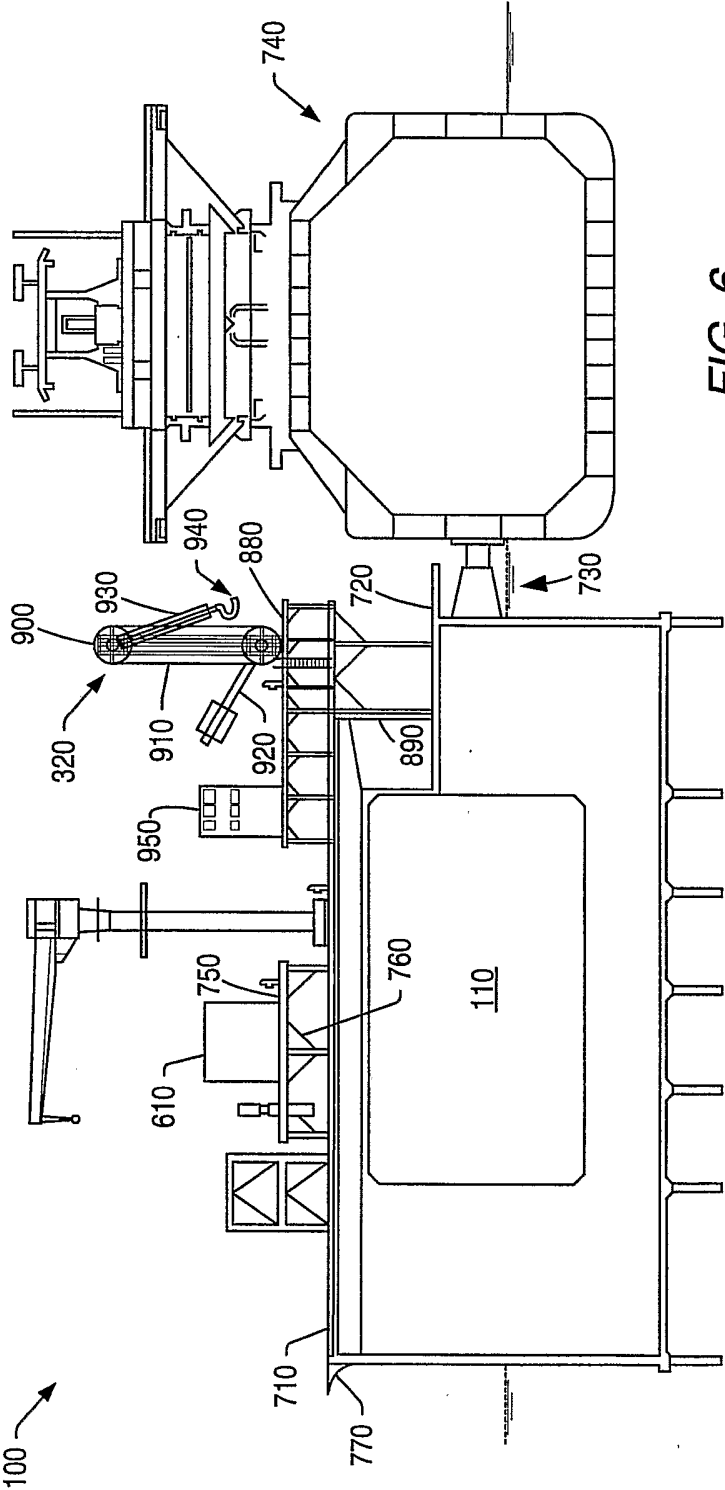


FIG. 6

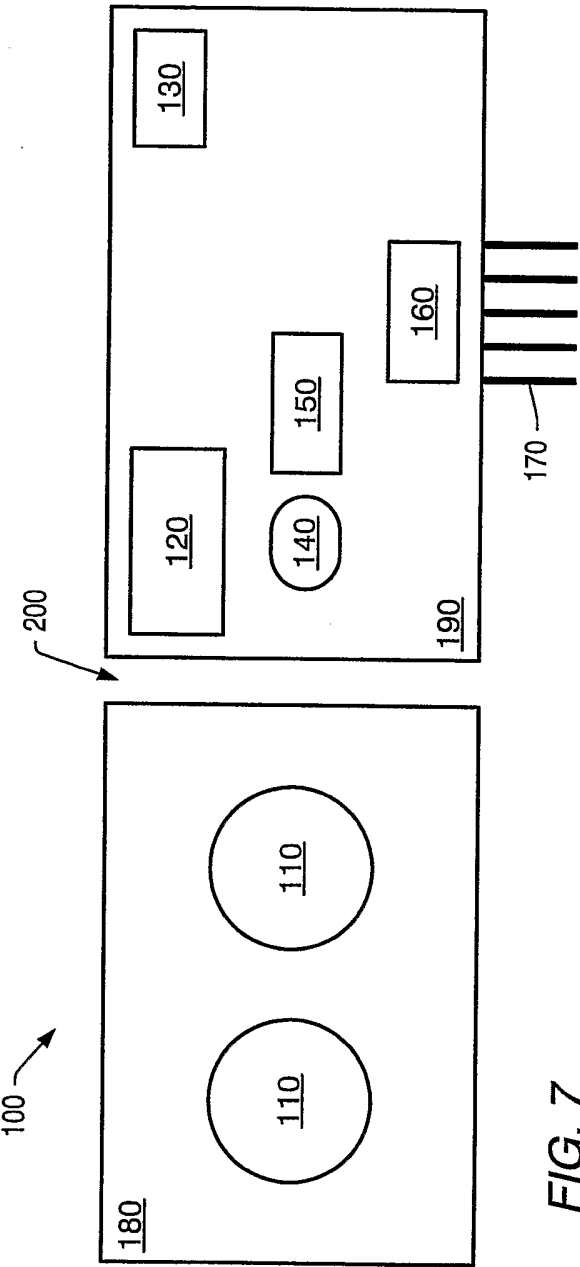


FIG. 7

NOT FURNISHED UPON FILING

INTERNATIONAL SEARCH REPORT

International Application No
PCT/US2004/036061

A. CLASSIFICATION OF SUBJECT MATTER

IPC 7 F17C3/02 F17C13/08 F17C7/04 F17C9/02 E02B17/00
B63B35/34 B63B35/44 B63B27/24

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

IPC 7 F17C E02B B63B

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

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

EPO-Internal

C. DOCUMENTS CONSIDERED TO BE RELEVANT

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A	WO 02/48602 A (OVE ARUP PARTNERSHIP LIMITED; JACKSON, GORDON; ROBERTS, JOHN; POWELL,) 20 June 2002 (2002-06-20) ----- -/--	

☒ Further documents are listed in the continuation of box C.

☒ Patent family members are listed in annex.

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- *&* document member of the same patent family

Date of the actual completion of the international search

4 February 2005

Date of mailing of the international search report

15/02/2005

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INTERNATIONAL SEARCH REPORT

International Application No
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