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Offshore Transfer, Re-Gasification and Salt Dome Storage of LNG

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Abstract

The paper describes a design family for 'ship to ship' and 'ship to shore' transfer systems for LNG. The common design philosophy is explained and each configuration is described briefly. Auxiliary systems and equipment are discussed as are operational procedures.

A case study is presented for a near shore LNG terminal, comprising a marine transfer system in combination with a re-gasification plant and a salt dome storage cavern. The re-gasification plant and the salt dome storage cavern are treated extensively.

The systems described will greatly advance the implementation of offshore terminals for LNG. Although new, all of the components used are proven and have been applied in LNG terminals and offshore loading systems longtime.

Introduction

LNG is the fastest growing hydrocarbon fuel; while gas as a primary fuel source is forecast to grow at 3% in the coming two decades, LNG as a subset is forecast to grow at double that rate over the same period.[1] The development of LNG has been encouraged by the enormous amount of stranded gas, a reduction in gas flaring, an ongoing 'greening' of the energy mix and several price spikes in natural gas prices. These many factors have stimulated growth of LNG production but also introduce 'commoditization' of LNG because of the substantial new sources of supply.

The U.S. is currently by far the world's largest gas market. Of the current supply 85% is produced within the US, and 15% is imported; 98% from Canada and only 2% in the form of LNG. Whereas U.S. demand is expected to grow with 2% per annum, the current U.S. gas production shows an increasing intrinsic decline rate and more newly discovered gas is needed each year to keep up with demand. No excess capacity exists at the wellhead. Current demand for winter heat is greater than storage and production.[2] In order to stabilize price, there is a need for increased storage capacity. With current producers struggling to maintain production, LNG is likely to capture a portion of the foreseen growth.

Community concerns, congested ports, security and cost considerations are seen to slow the development of significant increases in capacities to receive LNG in the U.S. and Europe. This paper will describe an offshore alternative to moor, unload, store and distribute gas sourced as LNG that has the potential to be faster to build, less expensive, much more secure, and more acceptable to the community than conventional alternatives.

Besides the liquefaction plants and shipping, a few key elements in the gas chain between production and delivery are the loading and offloading operations of the LNG ships, the re-gasification and the temporary storage of LNG and/or gas.

For the loading of LNG into the tankers and for the offloading thereof, terminals are required. The terminal at the loading side is normally close to the liquefaction plant. Traditionally on the offloading end, the terminal is situated near a temporary storage facility and re-gasification plant. After the LNG has been re-gasified, it is brought into the pipeline network to distribute it to the consumers. On locations with sufficient deepwater close to the coast or in ports, terminals may consist of jetty structures, where tankers can be moored and offloaded with standard midship side-loading arms. The LNG/Gas handling and storage can be done onshore.

In cases where conditions are less favorable due to shallow waters and / or congested shipping situations but also because of political reasons, offshore transfer, re-gasification and temporary storage can be an attractive alternative. Design work done to date shows that the transfer system, re-gasification and salt cavern based storage options are fully feasible. Again mentioning the U.S., there are numerous possibilities for these applications along the coast line and the design of the three components (transfer system, re-gasification unit and salt cavern based storage facility) are very flexible in the amount of LNG/gas to be handled.

Salt caverns can be solution mined in far less time and at about one fifth of the cost of constructing cryogenic tanks resulting in significantly lower investment and a shorter construction schedule. The permitting schedule will also be significantly shorter. Overall, these advantages result in a lower CAPEX and OPEX than for conventional terminals. Underground hydrocarbon storage is inherently secure as evidenced by the Strategic Petroleum Reserve's use of salt caverns to store more than 600 MM bbls of crude oil. A salt cavern based LNG receiving terminal can provide far more storage capacity and 'send out' capability than a conventional terminal. To support these statements, a case study for a LNG import terminal, re-gasification plant and a storage salt cavern to be located in the Gulf of Mexico is presented in the following, together with the status and an outcome of a recent study executed for the U.S. Department of Energy.

Transfer of LNG offshore

Given that both production and import of LNG will move more and more offshore, Bluewater recognized a need for a safe, efficient and reliable transfer system. Since there is a wide variance in waterdepth and environmental conditions between the potential sites a whole suite of concepts has been developed to serve each application's specifics, see figure [1]. All concepts share a common philosophy:

High System Availability. The investments made in the LNG production and transport chain are large thus so are the costs associated with downtime of LNG production and / or demurrage of the carriers. High system availability is achieved by using weathervaning mooring systems, a robust flow path and a minimum number of cryogenic mechanical components. All concepts are based upon proven components.

Suitability for Non-Dedicated Vessels. The current market trend indicates that a spot market for LNG is developing. To allow flexible and efficient operation of the terminal facilities, it is essential that vessels of opportunity can be handled. Thus transfer of LNG in all systems takes place at the midship manifold and only a minimum of adaptation of the LNG carrier is required.

Near Shore Terminal. Both for loading of LNG into the tankers and for offloading thereof, terminals are required. For locations with sufficient deep water close to the coast, terminals may consist of jetty structures and breakwaters, where tankers can be moored and offloading can take place via the standard loading arms.

In case the conditions are less favourable due to shallow waters, congested shipping and / or mooring situations, but also because of community acceptance and permitting, offshore terminals are a very attractive alternative. Although such terminals exist - they have been widely used for loading of crude oil and oil products for many years - no offshore terminals for LNG are in use.

The most dominant advantages of LNG offshore terminals are the lower costs for construction and operation, the possibility to locate the terminal in deeper water thereby eliminating the need for dredging and increased availability, safety and reduced voyage time as LNG carriers need not enter and manoeuvre in congested waters.

Based on its long time experience in mooring and offloading systems, Bluewater has developed a series of concepts for LNG terminals based on the premise of safe transfer of LNG offshore to and from non-dedicated tankers in wave heights of up to H_s = 5.0 m and flow rates of up to 10,000 m^3/hr. Three near shore concepts were developed:

Medium Waterdepth Terminal. This concept, dubbed 'Big Sweep' consists of three basic elements, see figure [2]:

- A jacket structure with turntable, anchored to the seabed
- A submerged rigid arm, hinged at one end to the jacket turntable and terminating at its other end with a buoyant column, and
- The LNG loading and transfer structure, located on top of the buoyant column.

To allow the vessel and arm to passively 'weathervane' into the most favourable direction with respect to the environment, the turntable is connected to the jacket structure by means of a bearing. This allows the turntable to rotate 360^o with respect to the jacket.

The turntable supports the rigid arm hinges, the cryogenic fluid swivels and the hawser attachment point. Optionally a helicopter deck, control/monitoring room and re-gasification equipment can be mounted.

The rigid arm consists of the following main elements:

- A hinge assembly, which allows the loading arm to pitch and weathervane relative to the jacket structure
- A structural lattice forming a rigid arm, and a
- A buoyant hull section which pierces the waterline and accommodates the LNG offloading equipment.

The overall length of the rigid arm is such that the buoyant column is positioned nominally near the midship cargo manifold of the LNG carrier. By adjusting the length of the mooring hawser the carrier's cargo manifold can be lined up to the offloading station for vessel sizes ranging from large to very large gas carriers.

The buoyant hull is equipped with a thruster system to swing the arm in a safe position during approach of the vessel and in-line with the vessel in the operational mode. A water ballast tank allows draft adjustment of the loading arm to match tanker size and / or drafts.

The standard fluid transfer system consists essentially of 3 Pipe-in-Pipe (PIP) lines. Two lines are dedicated to LNG; either in full flow mode or re-circulation mode. The third line is dedicated for vapour return.

The flow paths cross the weathervaning and pitch hinges between the jacket and the rigid arm. This is achieved with swivels and full metal jumpers which can be easily inspected and serviced.

The loading arm is normally trailing the jacket but can be temporarily 'parked' away from the LNG carrier line of approach, with its own propulsion. In this position the entire loading arm assembly cannot be damaged by a failed mooring approach of the export carrier tanker. Note that offshore tanker mooring to SPM systems is standard marine practice and that a failed approach run very rarely happens. Should the carrier 'brush' against the terminal, this will be a 'low energy' collision which can be accommodated by the fendering.

The LNG carrier moors in tandem with the turntable and once it has secured itself safely and the overall alignment is stable, the loading arm will be deployed from its parked position toward the vessel's manifold.

The hose deployment and loading operation may now be initiated. After completion of the transfer operations all of the steps discussed above are done in reverse order.

Emergency disconnection, such as may follow from e.g. hawser failure or excessive positioning difficulties (e.g. fishtailing) may readily take place by:

- Quick disconnect, allowing for the controlled closure of valves/pumps of the fluid transfer system, but includes all the typical emergency measures as known in normal terminals, and

- Activating full power on the thrusters to clear the rigid arm away from the export tanker returning it to its temporary parking position, giving wide berth to the LNG carrier.

Due to the relative high mass of the rigid arm, its long length compared to operating wave lengths and the small waterline area of the buoyant column, the heave motions (pitch) of the arm are very small and this has been validated in physical model tests in significant wave heights up to 9.0 m.

Shallow Waterdepth Terminal. Developed from the 'Big Sweep' system, this unit is designed to operate in waterdepths below 40 m, see figure [3]. It allows direct offshore-to-shore transfer of LNG, at rates up to 10,000 m^3/hr from non-dedicated vessels.

Motion characteristics are such that offloading can proceed up to significant wave heights of 3 m, depending on the waterdepth, which may be as little as 15 metres. For extreme survival conditions such as in the Gulf of Mexico, the free-end of the unit is water-ballasted and set temporarily on the seabed.

A self-positioning DP capability allows the unit to follow the LNG carrier manifold when loading or unloading LNG but drives the unit out of the way when the LNG carrier is mooring itself to the turntable on the jacket, thereby avoiding marine hazards.

Re-gasification equipment may be located on the unit for applications without LNG storage e.g. where gas is stored in salt caverns or delivered directly to the shore gas grid.

Offshore Re-Gasification Dock. The concept of a floating dock is not new, however in combination with a reduced displacement and connected to a Single Point Mooring (SPM) system, and also fitted with a simple but redundant Dynamic Positioning (DP) system, it becomes a powerful tool to:

- Berth standard LNG vessels offshore
- Enable unloading LNG through standard marine loading arms
- Allow transfer operation to continue in conditions up to 4 m significant wave height
- Provide a stable platform for a re-gasification plant
- Allow disconnection from its anchor legs for dry docking for campaign maintenance and / or modifications.

In essence the concept is based on mooring permanently a partly submerged dock, through an articulated rigid arm to a catenary anchor leg buoy, see figure [4].

The articulated rigid arm has been selected because it allows the dock to take up a position of sway and yaw relative to the buoy, when seen from above. Since the concept is based on having transverse propulsion means integrated in the dock, it is quite clear that with an LNG vessel mooring on the hawser messenger wire of the SPM and inching itself up to the buoy, the dock is now able to fully track the path the LNG vessel will follow, including yaw and sway. Hence the dock can simply maintain sideway clearance with the LNG vessel until it surfaces to contact the underside of the hull once it has completed its approach, see figure [5].

The amount of contact force is a function of operating environmental parameters and will be of such magnitude that no relative motions occur between vessel and dock. At all times contact forces are modest and can be easily accepted by the vessel. Effectively, the vessel is now fixed to the SPM through friction only. This in turn allows standard marine loading arms to be employed.

Given the displacement of the dock, a substantial load carrying capacity can be generated to support e.g. a full re-gasification plant. This allows gas to be exported to shore rather than LNG.

Of particular interest in this sense is the ability of the dock to release itself from the anchor chains and be taken into a harbour/yard environment for any major upgrades or campaign overhauls.

Finally, relocation of the unit to another gas-import location is well feasible.

Export from Production Barge. Currently operators are developing systems for Floating Liquid Natural Gas production and storage (FLNG).[3] Key to successful operation of such systems is safe and reliable means of transfer of LNG to the export vessel.

Current transfer concepts are based upon the traditional side-by-side configuration, or require the export vessel to be equipped with propriety connection equipment. Both factors adversely influence the availability and flexibility of the terminal, and so Bluewater has developed a number of concepts that circumvent these drawbacks.

Tandem Configuration. The 'Big Sweep' concept as previously described can also be deployed from a FLNG unit, see figure [6]. Such a system will enable offshore ship-to-ship transfer of LNG in tandem mode, which will increase the overall availability. The concept has the same components, albeit that a 3-axis joint is provided on the FLNG side of the arm.

The main differences between the two concepts are the motions of the FLNG. These, in combination with the steady arm result, in higher structural loadings.

Operationally, both systems are fully comparable. In non-operating conditions, the 'Big Sweep' will be parked alongside the FLNG which allows easy access to the buoyant column and the loading arms for Inspection Repair and Maintenance (IRM).

This concept has been physically model tested in the offshore basin of MARIN, The Netherlands. The tests confirmed the workability in sea states up to 5 m and survival condition of 9 m significant wave height. Moreover, the station keeping by DP has been verified and showed only modest power levels to maintain a 'follow me' mode.

Side by Side Configuration. Another concept has been developed as a variation on the traditional side-by-side configuration for transfer of LNG, see figure [7]. The key features of this concept are:

- Increase of safe distance between the FLNG barge and the export vessel during transfer operation
- Easier mooring up, fewer mooring lines and less personnel safety issues.

The concept works with a typical (short) low sway / yaw single point mooring type hawser attached to the end of a rigid arm which in turn is mounted on a turntable fitted to the barge. The required mooring elasticity is provided by a gas-hydraulic cylinder at the short end of the rigid arm on the barge.

The arm is able to swing freely forward in case the LNG carrier was to 'nudge' it that way.

An aft fender arrangement, based on a pivotal support arrangement, is provided near the end of the carrier's flat side shell, assuring that the 'near position' (i.e. bending radius control) of the flexible hose LNG transfer system is never compromised.

Although no model tests have been performed to date, Bluewater believes that safe mooring in conditions up to 3.5 m significant can be maintained.

Deepwater Remote SPM Dock. When transfer of LNG in side-by-side or tandem mode poses unacceptable operational constraints, export operations to the LNG carrier can be realized via a remote Single Point Moored Dock, see figure [8]. The system will be similar to the offshore dock described previously, but without the re-gasification plant. It will be located at a safe distance from the FLNG unit, typically 1 NM.

Transfer of product from the FLNG unit to the SPM dock will be via submerged full metal PIP lines. The transfer lines will be suspended via short chain sections from the SPM, jumpers forming the final connection to the dock's piping. This effectively decouples the dynamic rotations of the SPM dock from PIP transfer lines, reducing fatigue damage in the latter.

Fluid Handling System. The offloading equipment has been configured as a 'manipulator' from which the free end of either steel articulated loading arms or flexible catenary hoses are suspended. The advantage of this configuration is that it allows combining the free ends (3x Ø 20") into a single assembly, handled by direct mechanical means. Individual hose connections, although technically feasible, would lead to clash potential during high-offset emergency disconnects and also require more manpower in establishing first-line connections. The arrangement of the 'manipulator' is shown in figure [9].

The principle of the manipulator is based on supporting the free end of the flowlines (flexible or rigid) from a tension leg, which maintains a slight vertical tension on the vessel interface while fully accommodating low frequency heave of the 'Big Sweep', and the heave, pitch and roll of the LNG carrier. The tension is generated by a counterweight which is moved in the fore-aft direction as a function of the stroking out of the horizontal boom. A redundant load pin measures actual tension in the tension leg and adjusts automatically the counterweight position.

When the tension leg experiences an angle of tilt, due to relative motions between 'Big Sweep ' and the carrier, such angle is automatically detected and the manipulator horizontal boom length and azimuth angle are automatically adjusted to bring back the angular value below a pre-set value (say <10˚). The loads typically experienced by the manipulator assembly are in the same order of magnitude as normal offshore cranes and hence fully practicable. Since high frequency motions have no effect on the positioning demands, power demands are low. Beyond the pre-set limits, the tension leg will automatically initiate disconnect whereby the entire connector part is lifted up and away from the carrier.

The connector in the lower part of the tension leg consists of a structural part and a multi-path flow part. All connectors are made up of standard commercially available components. The structural connector is connected first, the flowpath connectors at that time still having a clearance at their mating faces of about 300 ~ 500 mm. Once the structural connector is secured, the flowpath connectors are stroked out to make up the connection. The structural connector is winched-down against the slight over pull of the tension leg. This allows that the 'first line' connection is made in-phase and avoids impact loads in case of large LNG carrier roll events. All elements of the tension leg and its connectors are designed to fail-safe.

The concept of the 'manipulator' allows significant automation of functions which enhances safety and limits manpower demand.

Case Study: LNG terminal offshore Gulf of Mexico

The goal of the U.S. Department of Energy cooperative research project, on which this paper's case study is based, is to define, describe, and validate, a process to utilize salt caverns to receive and store the cargoes of LNG ships. The project defines the process as receiving LNG from a ship, pumping the LNG up to cavern injection pressures, warming it to cavern compatible temperatures, injecting the warmed vapor directly into salt caverns for storage, and distribution to the pipeline network. The performance of work under this agreement is based on U.S. Patent 5,511,905, and other U.S. and Foreign pending patent applications. The cost sharing participants in the research study are The National Energy Technology Laboratory (U.S. Department of Energy), BP America Production Company, Bluewater Offshore Production Systems (U.S.A.), Inc., and HNG Storage, L.P.

Initial results indicate that a salt cavern based receiving terminal could be built at about half the capital cost, less than half the operating costs and would have significantly higher delivery capacity, shorter construction time, and be much more secure than a conventional liquid tank based terminal. There is a significant body of knowledge and practice concerning natural gas storage in salt caverns, and there is a considerable body of knowledge and practice in handling LNG, but there has never been any attempt to develop a process whereby the two technologies can be combined. Salt cavern storage is infinitely more secure than surface storage tanks, far less susceptible to accidents or terrorist acts, and much more acceptable to the community.

In particular, validation of the concept of an offshore, Gulf of Mexico, LNG receiving terminal, utilizing salt caverns for storage and the existing comprehensive pipeline system has profound implications for the next generation of LNG terminals. LNG imports are expected to become an increasingly more important part of the U.S. energy supply and the capacities to receive LNG securely, safely, and economically must be expanded. Salt cavern LNG receiving terminals both in onshore and offshore locations can be quickly built and provide additional import capacity into the U.S. exceeding 6 ~ 10 bcf / day in the aggregate.

Conventional Tank Based LNG Receiving Facility. A typical facility will have tank storage capacity for 2 to 3 ships' cargoes or about 5 ~ 8 bcf at standard conditions (250,000 ~ 380,000 m^3 in liquid form). The terminal will always have a LNG inventory in its storage tanks to keep everything cooled down. Typically the high-pressure pumps and vaporizers are the units limiting send-out as the facility can receive a cargo in 24 hours but takes from 3 to 6 days to discharge that volume as gas to the pipelines. There are four LNG terminals in the U.S. of this design, one of which is being refurbished. All have announced expansion plans but collectively the expanded terminals fall far short of the projected imports of LNG by 2020. Various alternate designs using cryogenic tank storage on floating vessels, shipboard re-gasification units or gravity-based structures generally take this same model and move it to sea.

LNG cryogenic storage tanks are expensive to build and maintain. Further, the cryogenic tanks are on the surface and present a tempting terrorist target. Several cargoes scheduled to be received after September 11, 2001 were delayed because of security concerns. There is therefore a need for a more secure, more economical, and higher capacity way to receive, store, and distribute LNG imports than has been done in the past.

Salt Cavern Based LNG Receiving Facility. The application of conventional salt cavern storage technology, augmented by new technology in the area of pumps, heat exchangers and facility design, could marry LNG and salt caverns into a highly secure, economical, flexible method to expand the Nation's energy supply.

Two key differences between a salt cavern based facility and a liquid tank based facility are that the caverns can be miles from the ship offloading facilities, and there is limited cryogenic liquid on site absent a ship. In a conventional terminal the liquid storage tanks must be in close proximity to the ship discharge site and considerable inventory is maintained between ships calls.

There are a number of salt formations, both offshore and near shore close to navigable waters where the caverns could be washed and developed into LNG receiving terminals. Salt cavern gas storage facilities have very high deliverability instantaneously available to the pipeline system, far higher than LNG vaporization capacities in conventional LNG terminals.

To illustrate the potential of this concept, a case study for an offshore LNG terminal with salt cavern storage is described in this paper. It consists of a marine terminal, which will receive LNG from the tanker. From there on LNG will be transferred to the injection platform, were it will be re-gasified and injected in the salt storage cavern. The injection platform has a seawater lift system; seawater will be used as warmant for the re-gasification process. Furthermore, the injection platform will accommodate a power generation plant fitted with a Waste Heat Recovery Unit (WHRU) to boost the seawater temperature, and a Living Quarters. Receipt and send-out of gas to the connecting pipelines will be controlled from the injection platform. Typical field lay-out is shown in figure [10].

Critical Elements. The major critical elements revealed in the cooperative research study are:

- Salt formations suitable for cavern development
- A pipeline infrastructure sufficient to carry large volumes of gas to market
- A method to moor and offload an LNG carrier and boost the LNG to storage cavern injection pressures at volumes that allow acceptable ship discharge times
- A heat exchanger design that will economically warm the LNG at high pressure and high volumes

Salt Formations and Storage Location. This case study locates the salt cavern storage facility in Vermilion block 179, a well-known salt formation in water approximately 100 feet deep, see figure [12]. This is sufficient for the drafts of any known and contemplated LNG carrier.

The rights to develop a salt cavern storage facility in U.S. territorial waters are obtained via lease from the Mineral Management Service. Such a lease would be granted on a 'non-interference basis' with any existing or future mineral exploration and production lease on the same blocks. This case study describes the development of six caverns, each initially of 2 MM bbls capacity, but maintaining a wash string in operation so that while in operation and over time they could be continually washed to greater capacities depending on the needs of the operator. These caverns could hold approximately 12 bcf of dense phase natural gas at 2,000 psi and be developed and placed in operation in 12 months. They could be subsequently enlarged to 4 MM bbls each for a total storage capacity of 24 bcf at a subsequent additional cost of less than $ 2 million. Larger caverns with increased storage capacity are feasible.

In the U.S. there are more than 300 known salt domes and countless acres of salt strata many of which are located in offshore territorial waters. For a cross section of a salt dome refer to figure [13]. Salt domes, 'pillows', or thick salt strata suitable for the development of hydrocarbon storage caverns are also known to exist in other areas of the world including Mexico, Northeast Brazil, Europe, and China. A well can be drilled into the salt formation and fresh water or seawater can be injected through the well into the salt to create a cavern. Salt cavern storage of hydrocarbons is a proven technique that is well established in the oil and gas industry. The drilling program, casing requirements, solution mining techniques, monitoring, logging and testing are all well developed practices. Permitting by the MMS is expected to follow practices used by state agencies that permit these types of facilities presently. Discharge of the saturated brine created by solution mining at sea is currently permitted and practiced in the U.S. and in several other countries where cavern development is practiced. Salt caverns have high send-out capacity, are very secure, and are very inexpensive to create and maintain compared to surface tanks, particularly cryogenic tanks.

When fresh or seawater is injected into a salt formation, it dissolves thus creating brine, which is returned to the surface. The more fresh or seawater that is injected into the salt formation, the larger the cavern becomes. The top of the salt formation found in Vermilion block 179 is at depths of less than 1000 feet and has a horizontal extent of more than one mile. A salt cavern is an elongate chamber that may be up to 1,500 feet in length and have a capacity that varies between 3 ~ 15 MM bbls. The largest is about 40 MM bbls, in crude oil service in the U.S. Strategic Petroleum Reserve. Each cavern itself needs to be fully surrounded by the salt formation so nothing escapes to the surrounding strata or another cavern. Multiple caverns will typically be formed in a single salt dome.

Presently, there are more than a 1,000 salt caverns being used in the U.S. and Canada to store hydrocarbons. Storage in salt caverns exceeds 1.2 billion bbls of hydrogen, natural gas, natural gas liquids, olefins, refined products, and crude oil. In the U.S. the salt cavern storage sites form a logistical connection between the gas, gas liquids, refining and petrochemical industries, resulting in the most comprehensive, efficient energy/processing infrastructure in the world.

Explorationists have known the locations of salt formations in the Gulf of Mexico for some time because of their interest in oil accumulations on the salt dome flanks and sub-salt. The first offshore oil wildcat well drilled in the Gulf of Mexico was drilled on the flanks of a salt formation in the Ship Shoal blocks in the late 1940's. Hydrocarbons do not dissolve or pass through the salt so the outer boundaries of salt formations are known as excellent 'traps' for hydrocarbon accumulations.

The Pipelines. This case study contemplates connecting the salt cavern based LNG receiving facility to three of the largest natural gas systems in the Gulf of Mexico, namely Bluewater, Sea Robin, and Texas Eastern. It is believed that there is 2 bcf / day of available take away capacity in these systems. Looping the connections or extending connections to additional systems could expand on the available capacity.

The Gulf of Mexico has an extensive pipeline network to transport produced oil and gas for processing and distribution. On average, close to 15 bcf / day is moved onshore in this gathering system with estimated additional capacity to be close to 5 bcf / day. This indicates that there is capacity available to move imported LNG from salt cavern storage sites to markets in the existing infrastructure. Over twenty potential sites were evaluated during the DOE research project that combine salt formations suitable for storage cavern development in proximity to existing pipeline capacity. Vermilion block 179 was selected for this case study but there are many attractive sites.

Marine Terminal. For the case study the shallow waterdepth terminal as described earlier in the paper, was selected as the most suitable concept.

Transfer from the ship's manifold to the weathervaning arm will be via two cryogenic flexible hoses supplemented by a vapor return hose. On the fixed jacket structure, a series of high-pressure LNG pumps will be provided to boost the LNG from the ship's discharge pressure of about 50 psi to the storage cavern pressure of 2000 psi. A schematic diagram is shown in figure [11]. This arrangement allows the cryogenic hoses and swivels to be of low pressure rating. Power for the pumps will be provided from the injection platform via High Voltage subsea cable. A small re-gasification plant will be provided on the arm to provide vapor return to the LNG carrier.

The high pressure LNG pumps proposed cross no technological barriers from those that are in common use at lower pressures (1400 psi) Limiting factors of the pump's capacity are the power requirements of its drivers which limit each pump to about 2000 horsepower. Unloading rates in the 8,000 ~ 10,000 m^3/hr can be achieved with multiple pumps and are the design basis for the case study facility.

The LNG will be pumped to the injection platform, located approximately 1 NM away, via two Ø 20" PIP cryogenic subsea flowlines. Note that the design of these will be based primarily on (thermal) stress considerations, and not so much on thermal efficiency, as the LNG will be re-gasified.

LNG Heat Exchangers. Conventional designs of heat exchangers can be utilized to warm the resultant high-pressure LNG but capacity limitations and energy consumption dictated a new approach resulting in the patented Bishop Process Heat Exchanger.

The Bishop Process warms LNG using seawater as warmant and stores the resulting dense phase natural gas (DPNG) in a salt cavern, or discharges it to a pipeline or both. The volume ratio of warmant to LNG, the number of warmant injection points and the preheating of the warmant and/or the LNG can be incorporated on a site-specific basis.

To accomplish heat exchange in a horizontal flow configuration, such as the Bishop Process, it is important that the cold fluid be at a temperature and pressure such that it is maintained in the dense or critical phase so that no phase change takes place in the cold fluid during its warming to the desired temperature. This eliminates problems associated with two-phase flow such as stratification, cavitation and vapor lock.

The dense or critical phase is defined as the state of a fluid when it is outside the two-phase envelope of its pressure-enthalpy phase diagram. In this condition, there is no distinction between liquid and gas, and density changes on warming are gradual with no change in phase. This allows the heat exchanger of the Bishop Process to reduce or avoid problems with two-phase gas-liquid flows. The effect of confining the fluid to the dense phase is illustrated by an analysis of the densimetric Froude Number F that defines flow regimes for layered or stratified flows:

$$F = V\left(gD\frac{\Delta\gamma}{\gamma}\right)^{-\left(\frac{1}{2}\right)}$$

Here V is fluid velocity, g is acceleration due to gravity, D is the pipe diameter, γ is the fluid density and $\Delta\gamma$ is the change in fluid density. If F is large, the terms involving stratification in the governing equation of fluid motion dropout of the equation. As a practical example, two-phase flows in enclosed systems generally lose all stratification when the Froude Number rises to a range of from 1 to 2. In this application the value of the Froude Number ranges in the hundreds which assures complete mixing of any density variations. These high values occur because in dense phase flow, the term $\Delta\gamma/\gamma$ in the equation above is small.

Measurement of the Froude Number occurs downstream of the high-pressure pump systems and in the heat exchangers. Process simulations using HYSIS and the finite element modeling conducted as part of the research project indicate that the heat exchange occurs as predicted, icing is controlled, and energy consumption for the system is significantly lower than that experienced in conventional liquid tank terminals.

Facility Operations. The LNG ship mooring and unloading procedures are described previously in the paper.

The ship's discharged LNG will be presented to the inlet of the high-pressure LNG pumps at around 50 psi and -260^o F.

at rates between 8,000 and 10,000 m^3/hr. The high-pressure LNG pumps will boost the LNG to approximately 2,000 psi and discharge to the heat exchangers. The discharge temperatures from the pumps to the heat exchanger would be higher than the inlet temperatures and is considered in the design of the heat exchangers. Seawater would be introduced into the heat exchangers in a counter flow manner and the resultant discharge of dense phase natural gas from the heat exchangers would be at 2,000 psi and design temperatures of plus 40^o F. Cryogenic tolerance and expansion considerations are accommodated by a combination of metallurgy and mechanical design. Generally the volumetric difference between LNG at atmospheric pressure and dense phase natural gas at 2,000 psi and 40^o F is one to three so there is a velocity increase in the warming process and consideration is given in the piping and cavern design to allow for this expansion.

The dense phase natural gas will be injected directly into the caverns and/or the connecting pipelines with appropriate pressure control as necessary. Upon completion of the cargo unloading the entire cargo parcel will be handled in one time leaving only enough LNG on site on the inlet side of the high-pressure pumps to maintain them in a cryogenic state.

The operation of the salt cavern storage caverns, their maintenance and inspection would be identical to those practices in the 100 plus natural gas storage caverns in operation in North America and Europe.

A difference between the operation of salt caverns used in LNG receiving and conventional natural gas storage is the high rates of injection into the caverns compared to most facilities. Conventional natural gas storage in salt caverns use compressors to boost the pressure of inlet gas to cavern injection at rates generally between 0.5 ~ 1 bcf / day. This application would involve injections rates of 3 ~ 4 bcf / day which is accommodated by multiple caverns and wells. A significant energy savings occurs in pumping LNG compared to compressing natural gas. A geo-mechanical temperature and rock mechanic analysis conducted as part of the research project indicate that injections to the caverns and withdrawals from them at the design rates described are within salt tolerances.

Conclusion

The adaptation of well accepted marine technologies; with equally well-accepted salt cavern storage technologies have the potential to accommodate a significant increase in the world LNG trade. Areas of the world that are projecting significant increases in import requirements of LNG, namely the US, Western Europe, China, and Mexico have a need for new methods for importing, storing and distributing LNG. Offshore terminal locations far from populated areas and congested ports will heighten community acceptance and reduce security concerns. The use of salt caverns can result in an LNG import terminal that compared to a cryogenic tank based terminal is much more secure, is much less expensive to build and operate, and can have both higher storage capacity and higher take away capacity. Northeast Asia has been the major traditional destination of the world's LNG but that is changing. The adoption of the well-developed technologies described in this paper has the potential to accommodate a virtually unlimited increase in LNG imports to the high growth areas of the Americas, Europe, and China.

Acknowledgements

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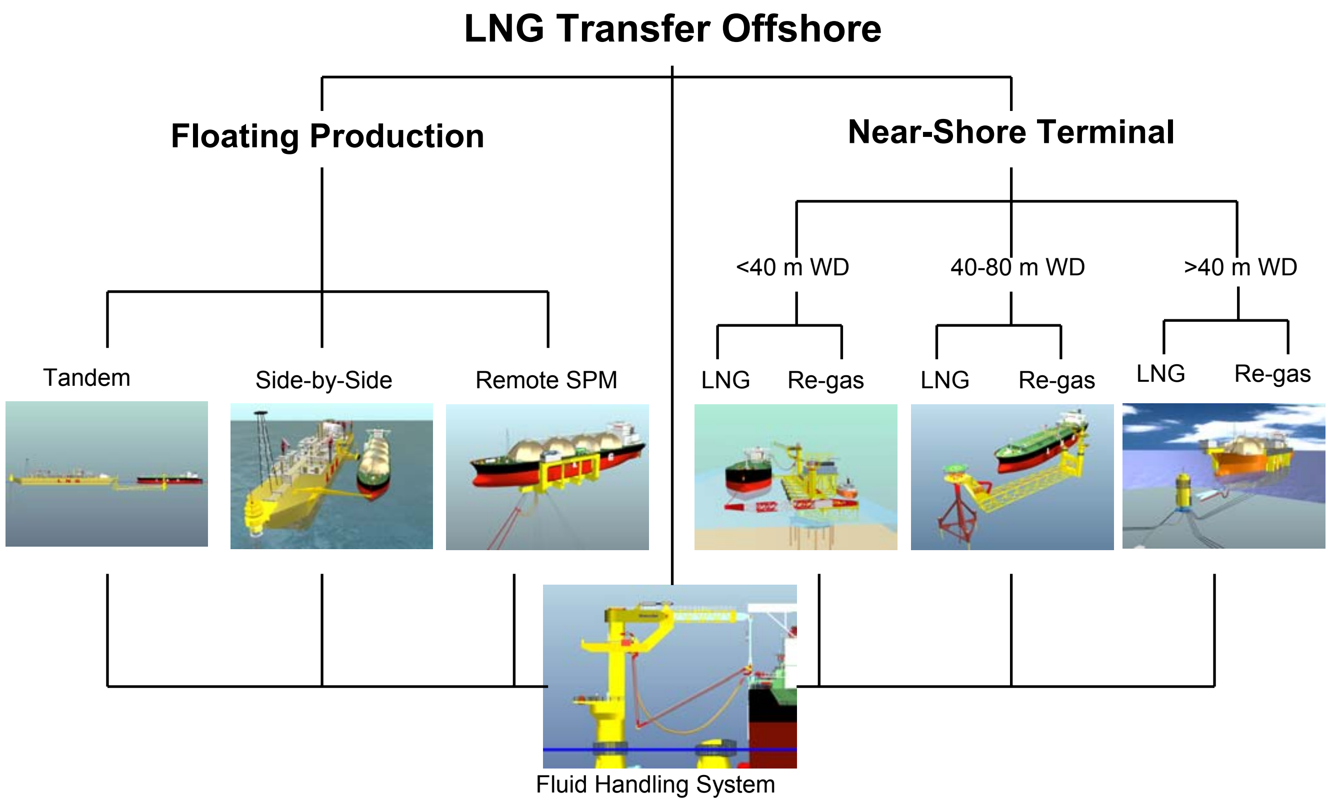

Figure 1: Design Concepts for LNG Transfer

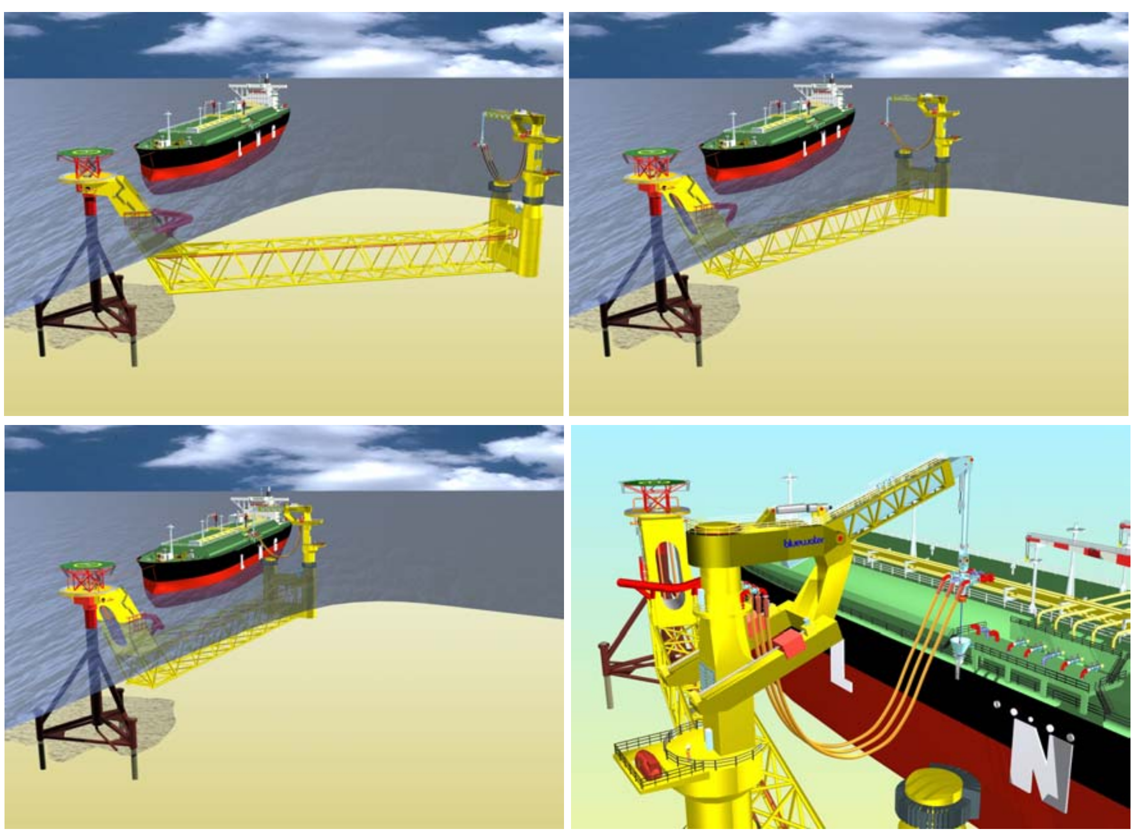

Figure 2: Medium Waterdepth 'Big Sweep' Terminal

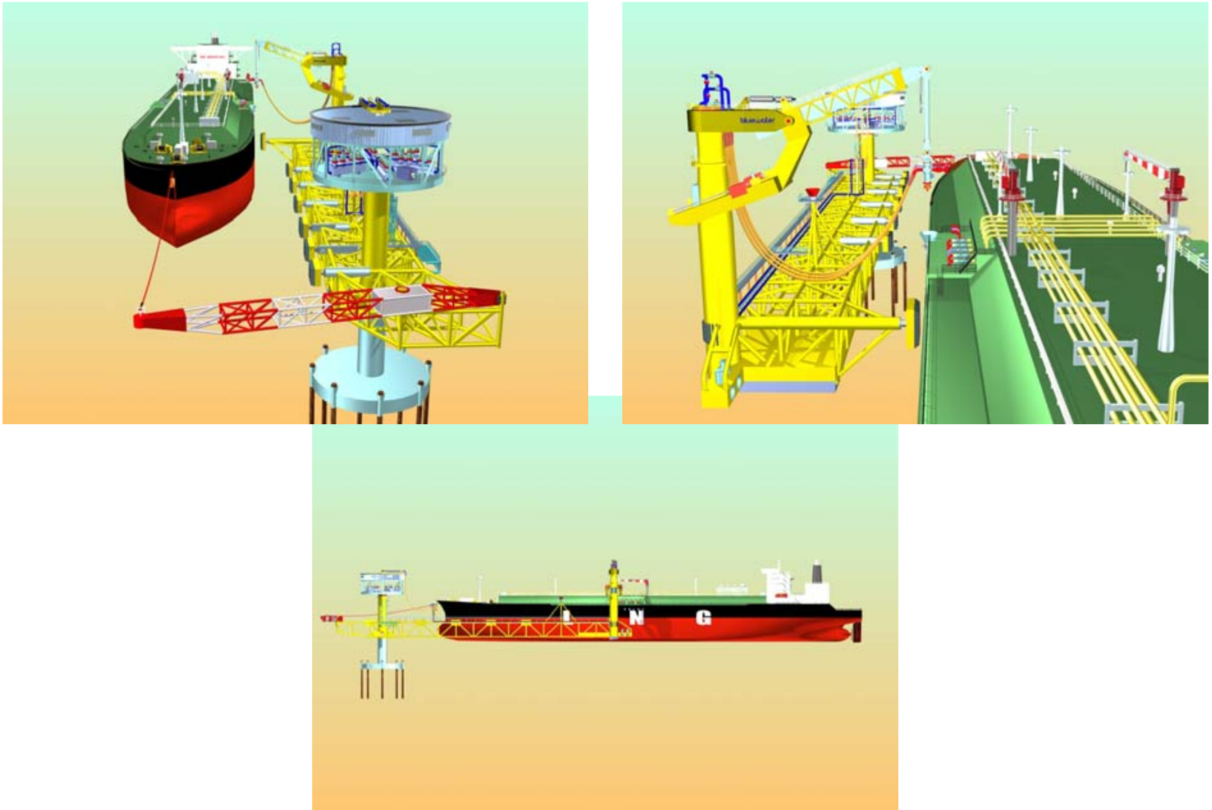

Figure 3: Shallow Waterdepth 'Big Sweep' Terminal

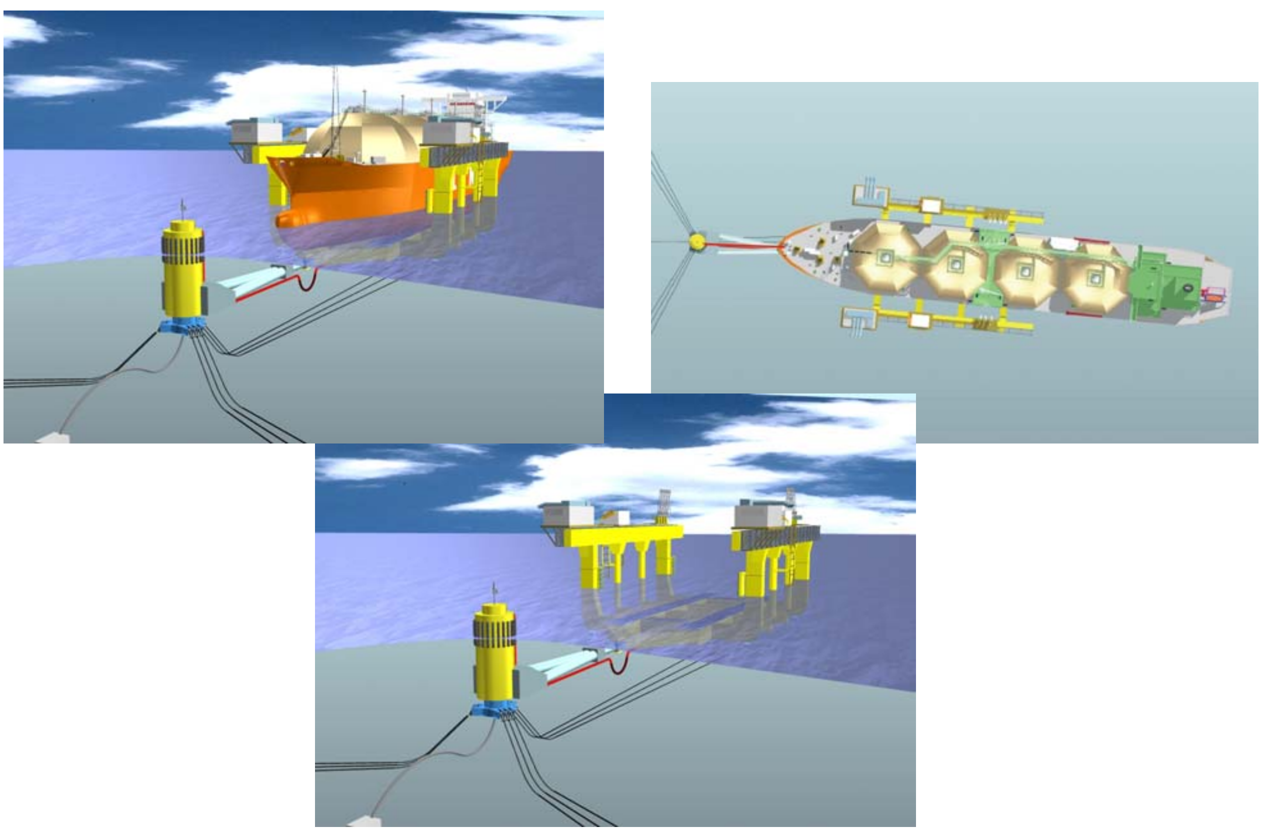

Figure 4: Offshore Re-Gasification Dock

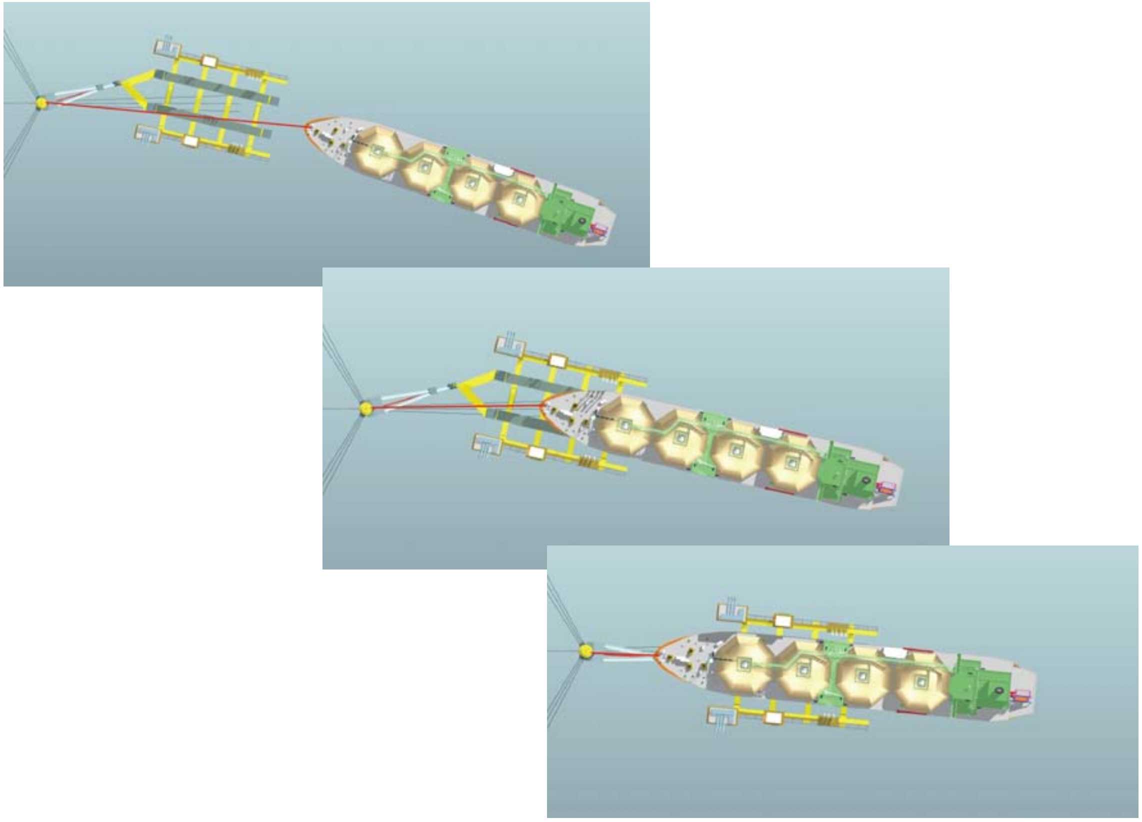

Figure 5: Berthing of LNG Carrier into Offshore Dock

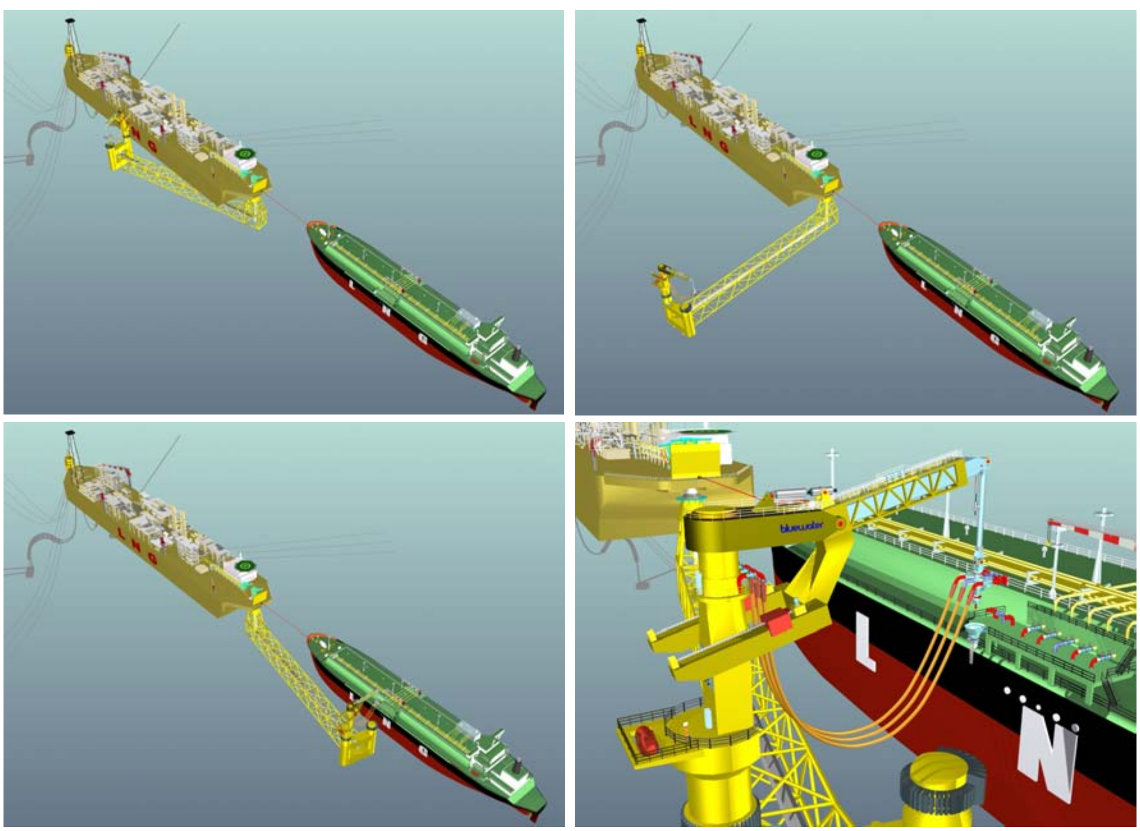

Figure 6: 'Big Sweep' for Tandem Export from FLNG Barge

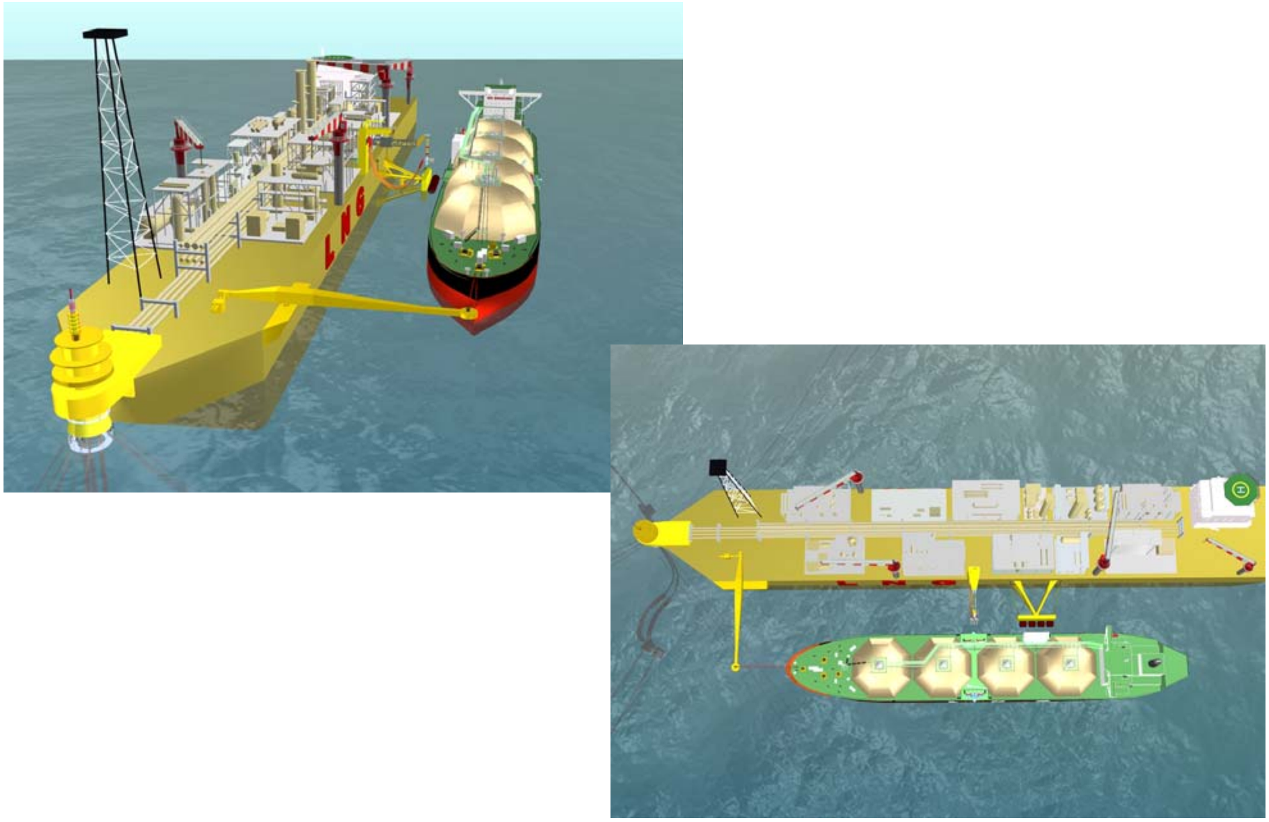

Figure 7: 'Side by Side' Transfer from FLNG Barge

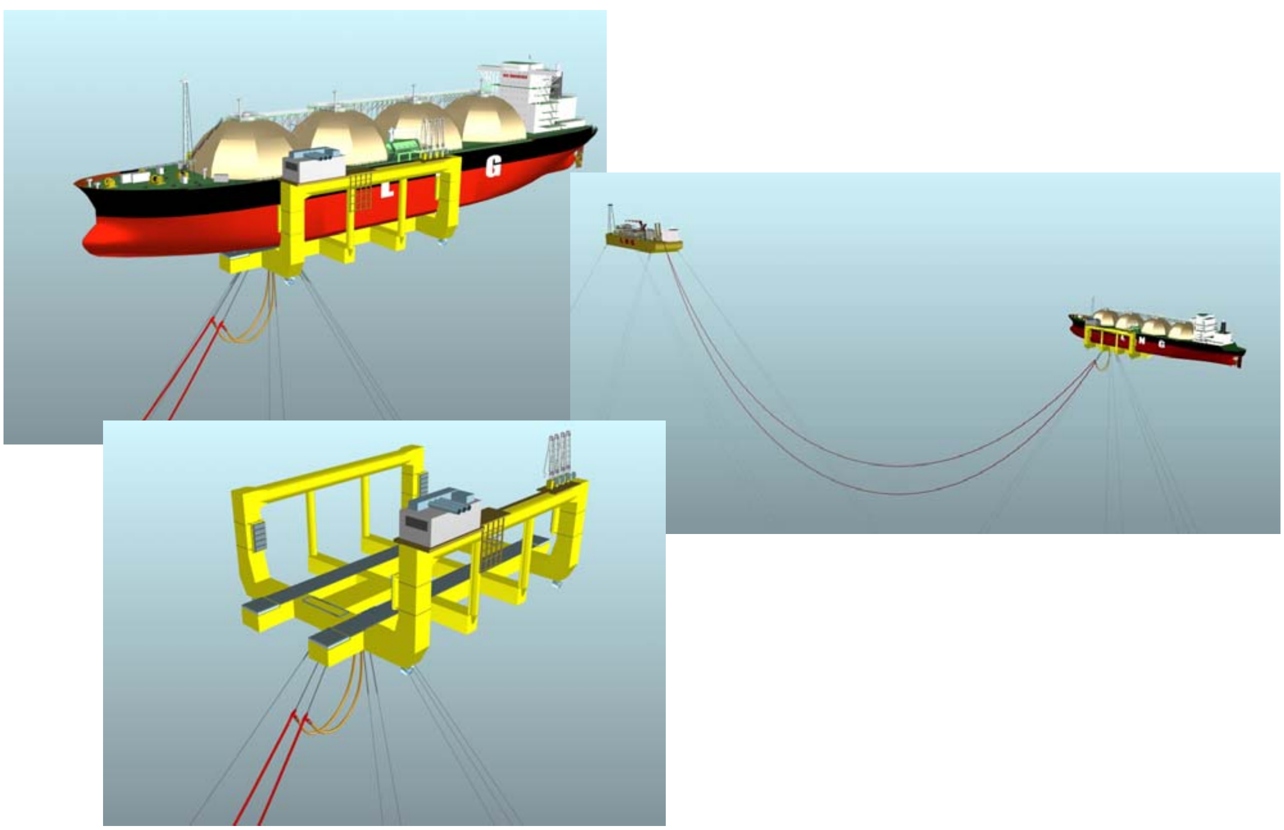

Figure 8: Deepwater Remote SPM Dock

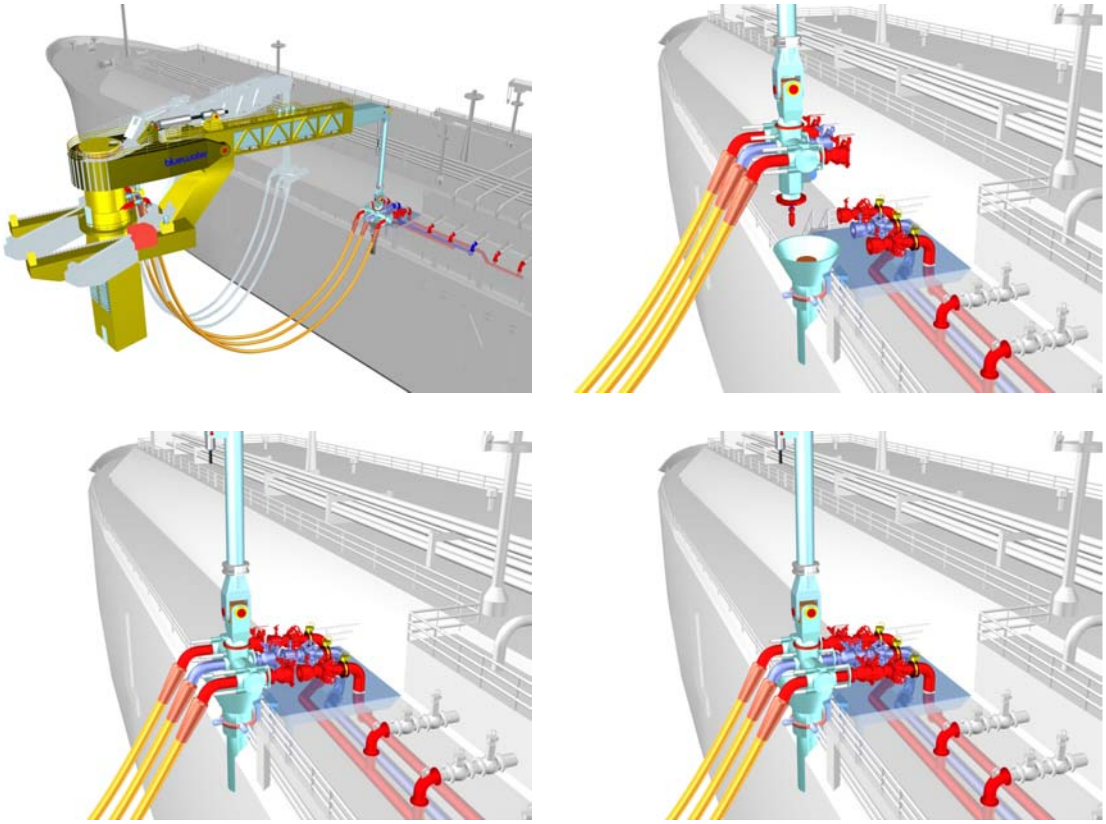

Figure 9: Manipulator for LNG Transfer Hoses

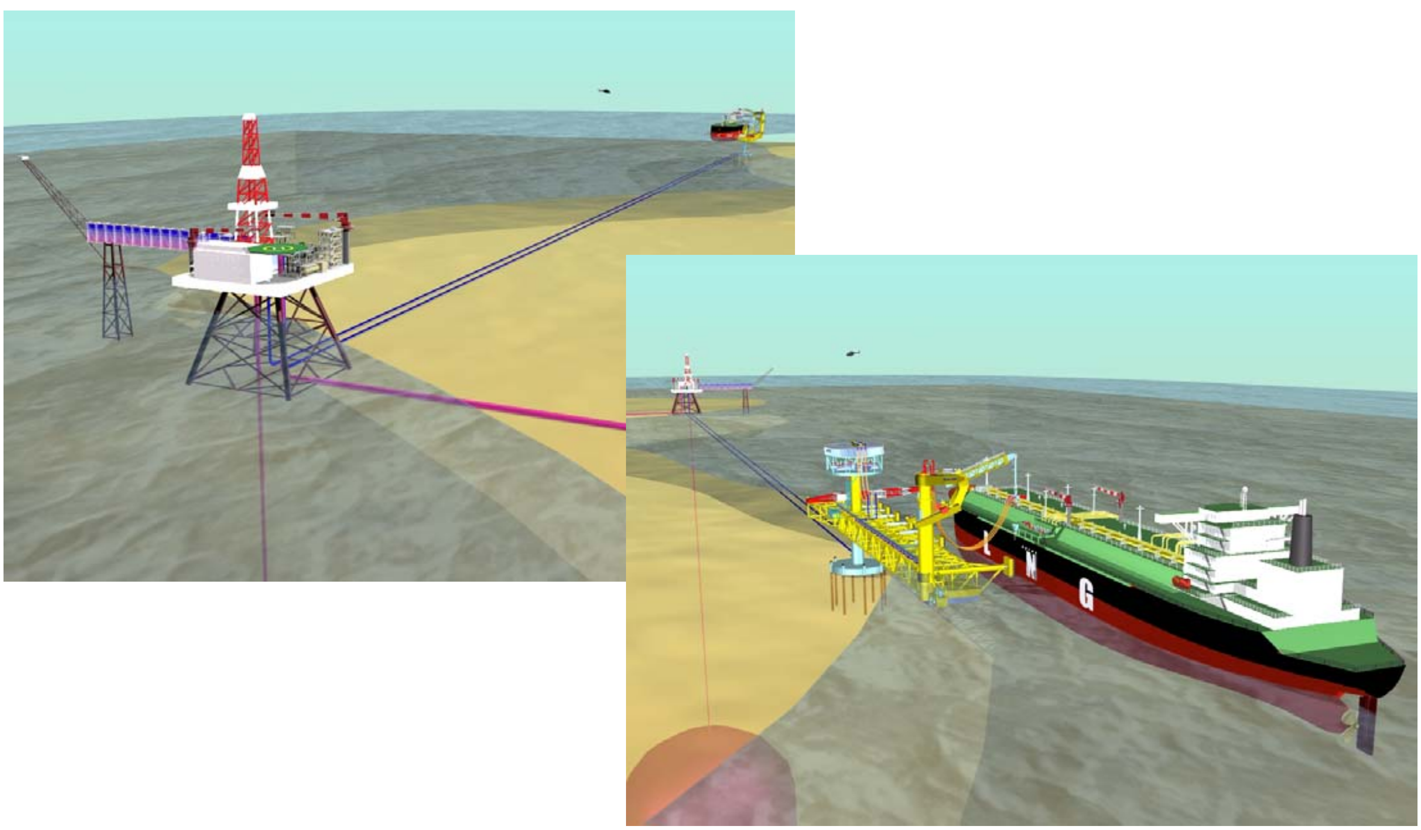

Figure 10: Case Study – Field Lay-out for LNG Import Terminal with Salt Cavern Storage

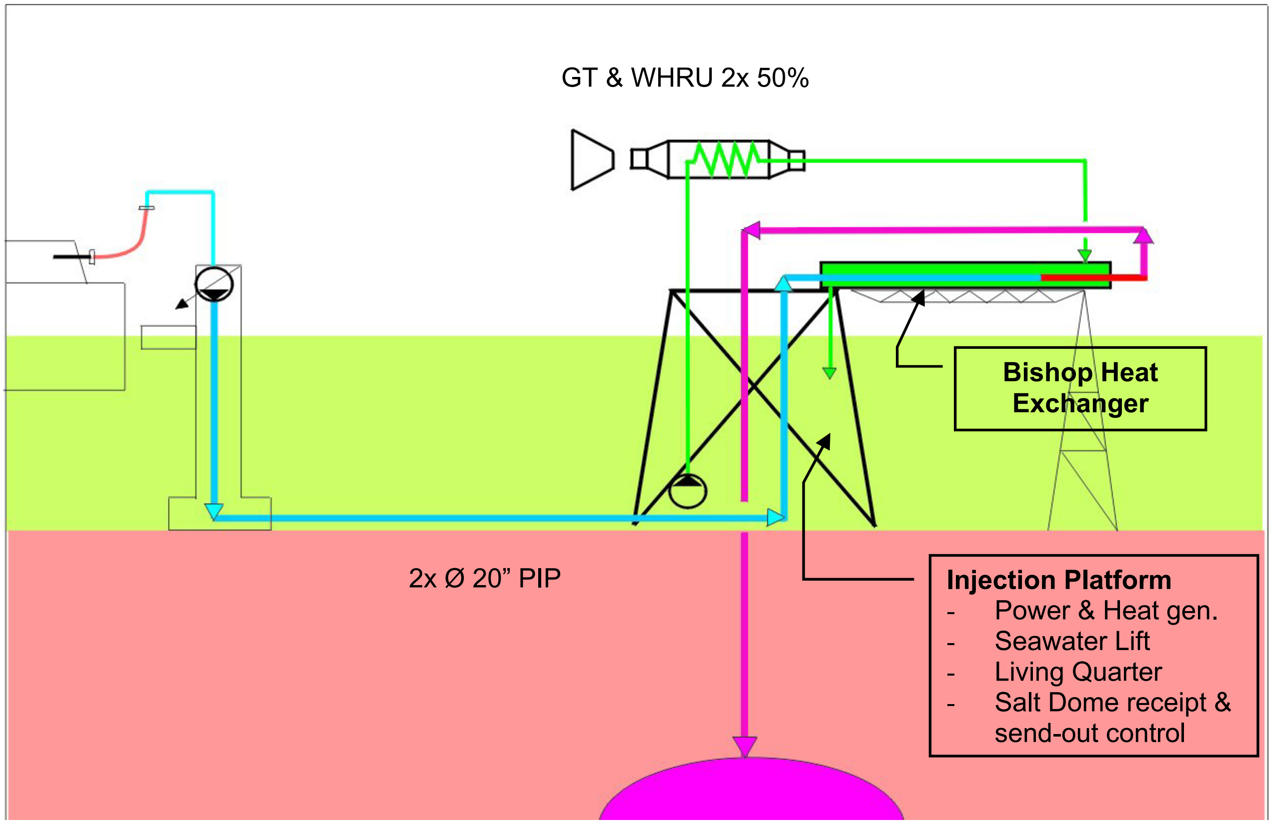

Figure 11: Case Study – Process Schematic for LNG Import Terminal with Salt Cavern Storage

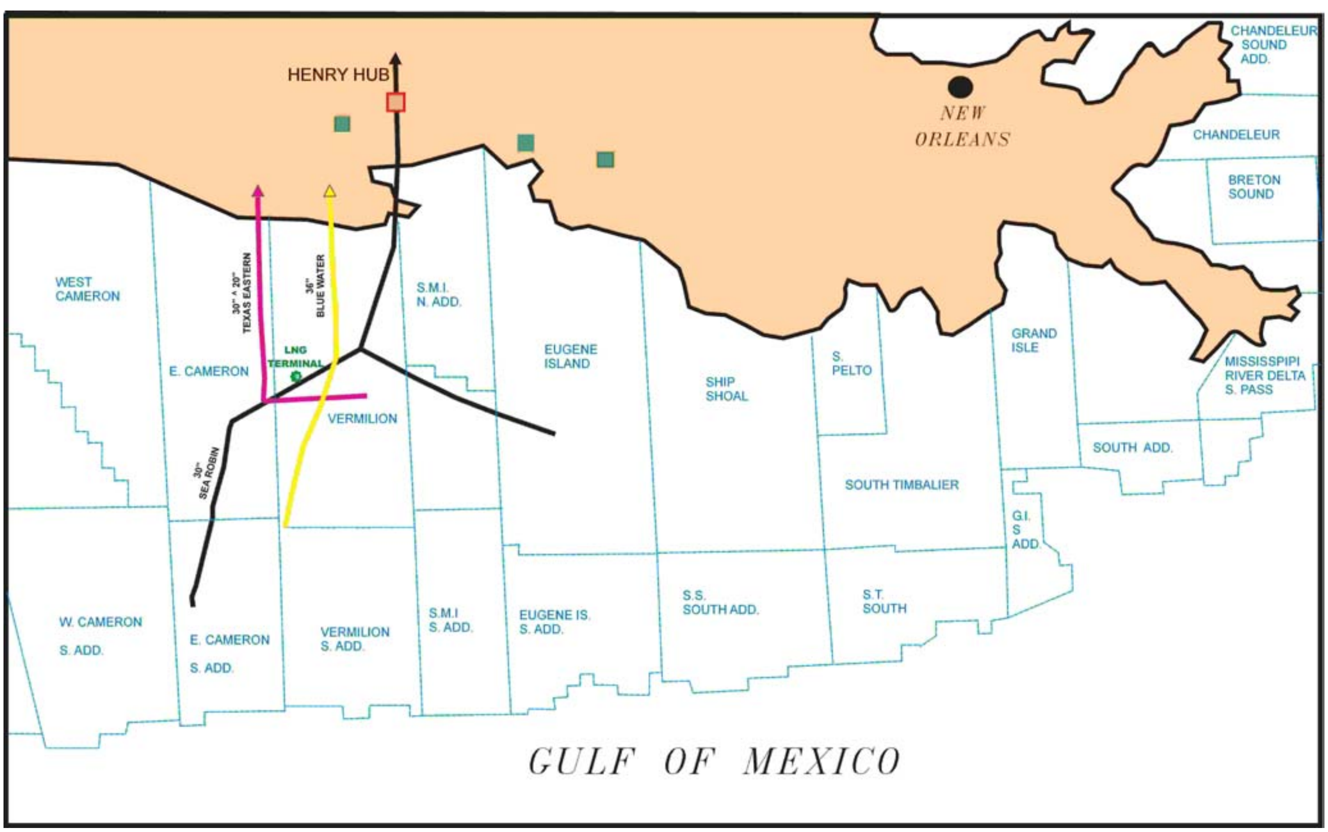

Figure 12: Case Study - Location of LNG Import Terminal – Vermillion Block 179

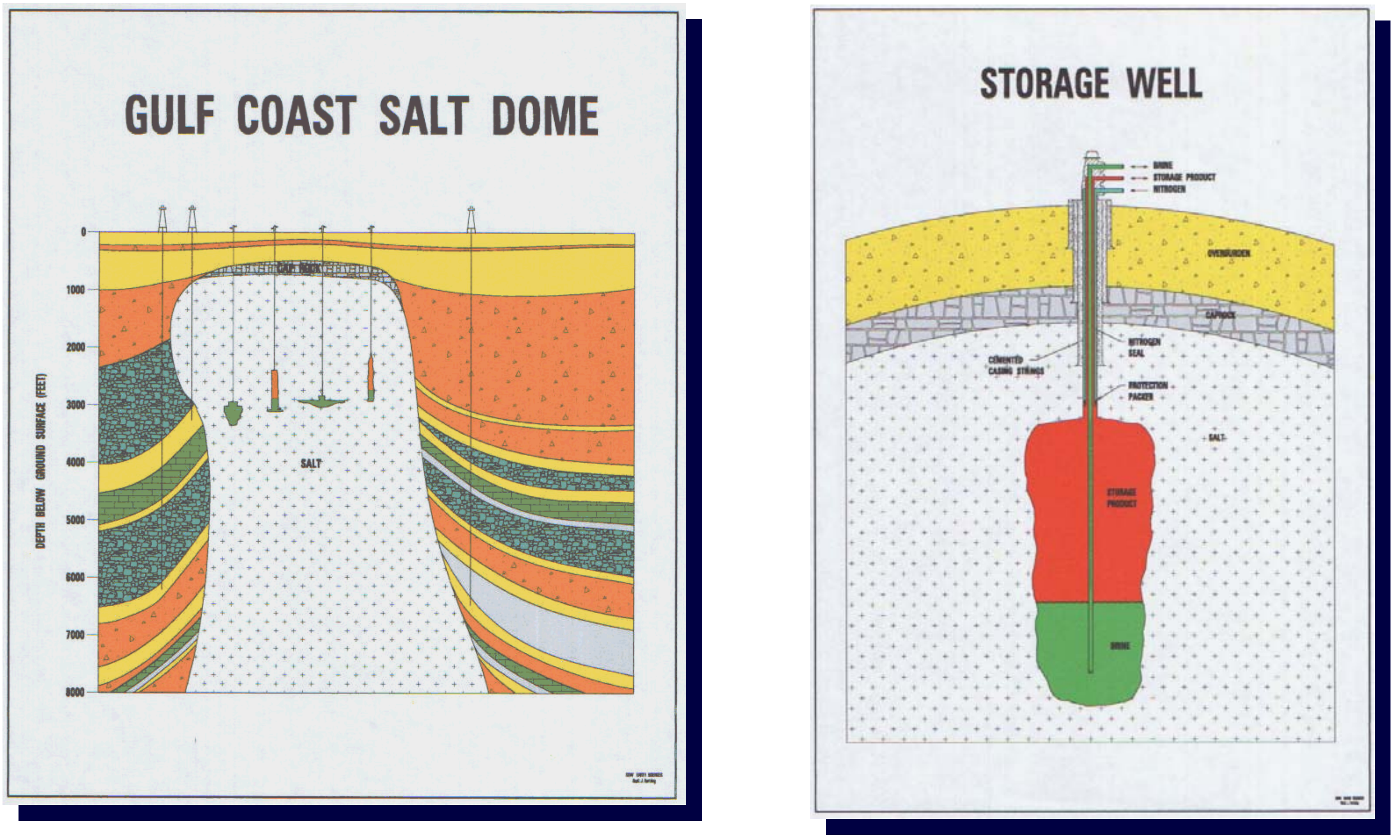

Figure 13: Cross Section over Salt Dome