PROCESSES AND PUMP SERVICES IN THE LNG INDUSTRY

by

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ABSTRACT

The liquefied natural gas (LNG) industry continues to grow worldwide, and there are many LNG terminals planned for the US in response to growing natural gas demands. This tutorial covers the LNG supply chain with emphasis on pumping services at each step along the chain including liquefaction, shipping, and receiving. This paper presents an overview of LNG processes and the service parameters that make pumps in the LNG industry unique.

THE LNG CHAIN

Figure 1 shows the elements of the LNG chain. The chain starts with gas production, usually from offshore wells though some plants receive gas from onshore sources. The gas produced can be from a gas field (nonassociated gas) or may be produced along with oil (associated gas). The distinction between associated and nonassociated gas is important because associated gas must have liquified petroleum gas (LPG) components (i.e., propane and butane) extracted to meet heating value specifications of the LNG product.
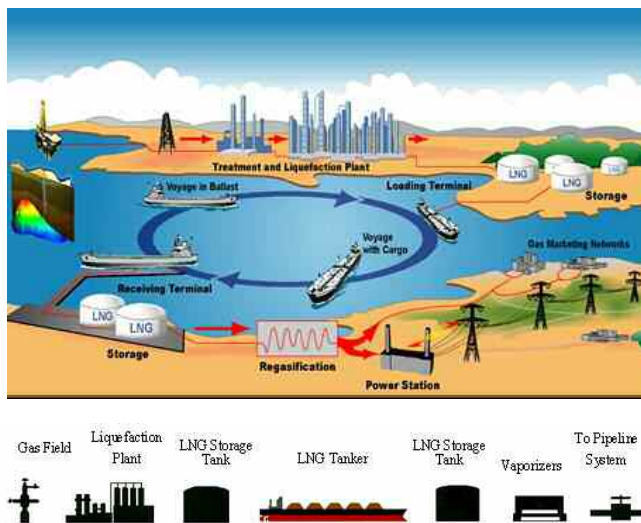

Figure 1. The LNG Chain—From Production to User.

The produced gas enters the LNG liquefaction facility and goes through several steps of treating before being liquefied. The LNG leaving the liquefaction plant must be stored until a ship arrives to transport the product. Although it would be possible, in theory at least, to run down the product directly into the ship and greatly reduce or eliminate storage. Storage tanks are less expensive than ships and economics favor storage at the facility.

For a facility making 8 MMTPA a 140,000 m^3 LNG ship will arrive every three days. A single ship holds enough energy to meet the natural gas needs of 33,000 Americans for one year, and at a gas price of $3.00/MMBtu the cargo is worth about $10 MM. The ships are powered by steam engines and typically travel at 19 knots; thus, a round trip voyage of 5000 miles takes between nine and 10 days of travel plus at least a day of turn-around at each end for a total duration of 12 days. The time it takes to load a ship once the loading pumps are started is about 12 to 14 hours.

The LNG ships unload at the receiving terminal using their cargo pumps. The receiving terminal stores the LNG, which is vaporized and sent out into a pipeline, or in some cases directly to an electric power plant (commonly done in Japan).

THE LNG LIQUEFACTION FACILITY

The liquefaction facility is the greatest contributor to the LNG price at the receiving end, with the possible exception of shipping depending on distance to market. LNG plants produce LNG and condensate (natural gasoline) products, and in some cases LPG (propane and butane).

Liquefaction Process

A block flow diagram of the liquefaction process is shown in Figure 2. The first step in the process is removal of acid gases such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S). CO_2 would freeze at cryogenic process temperatures and H_2S must be removed to meet the LNG product specifications. Typical specifications for acid gas removal are 50 ppm for CO_2, 4 ppm for H_2S, and total sulfur content less than 25 ppm. An amine solvent process is most common for acid gas removal. The process has an absorber tower where "lean" solvent contacts the natural gas and absorbs acid gas components, thus becoming "rich" solvent. The rich solvent leaves the bottom of the absorber and regenerates with a drop in pressure and heating in the stripper tower. The regenerated solvent is now "lean" again and cooled and pumped up to the absorber pressure.
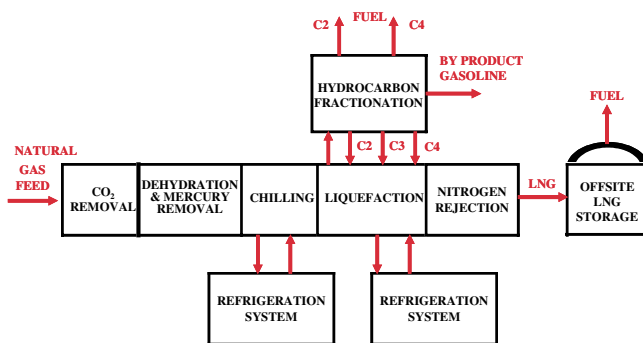

Figure 2. *Liquefaction Process Block Flow Diagram.*

Figure 3 shows a simplified process flow diagram for acid gas removal. The amine solvent pumps are often the largest pumps in the plant, especially when the natural gas contains a high amount of CO_2 (10 to 15 mol% CO_2 is considered high though some natural gas reserves have even more). The solvent can be monoethanolamine (MEA), diethanolamine (DEA), methyldi-ethanolamine (MDEA), Sulfinol, diglycolamine (DGA), or others, but the current trend is toward activated MDEA-based solvents.

The gas leaving the acid gas removal unit is saturated with water from the amine solvent, and a dehydration unit removes the water. The dehydration unit consists of multiple mol sieve beds and regeneration equipment. Typically two mol sieve beds run in adsorption mode while a third bed regenerates. Hot, dry natural gas flowing through the bed accomplishes the regeneration. After regeneration, cool natural gas cools the bed, and then the bed cycles into adsorption mode while one of the other beds cycles to regeneration.

The treated and dry gas now enters the liquefaction unit that chills and liquefies the gas in a refrigeration process. Figure 4 is a drawing of a process that makes about 85 percent of the world's LNG production. A multiple stage propane refrigeration system first chills the gas through a series of heat exchangers down to about −30°C. The natural gas drops out liquids at this temperature, and the scrub column removes these heavy liquids (especially benzene and other aromatics) that would otherwise freeze in the main cryogenic heat exchanger.
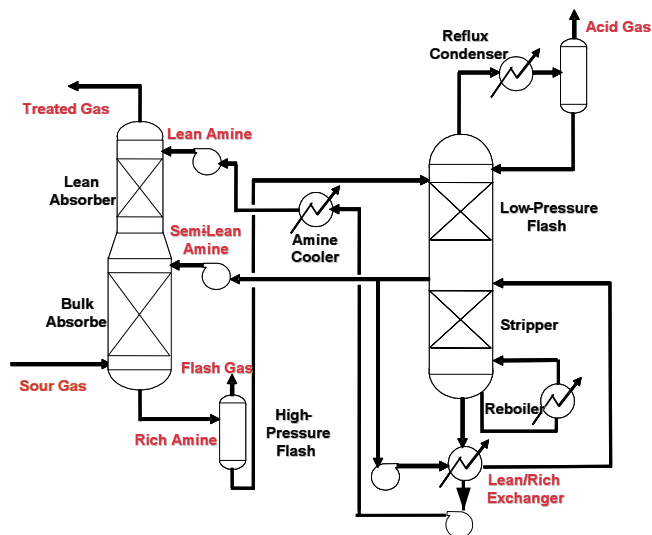

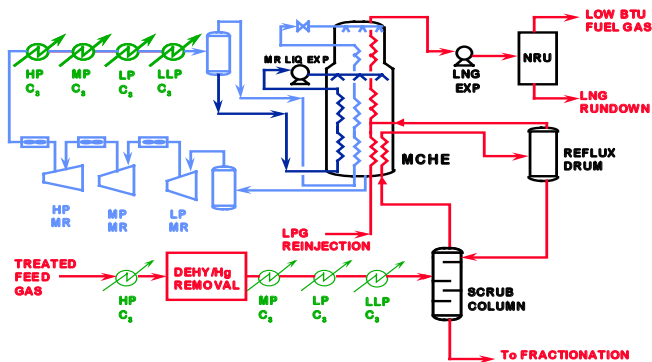Figure 3. *Acid Gas Removal Process Flow Diagram.*

Figure 4. *Liquefaction Process Flow Diagram. (Courtesy of APCI)*

The natural gas leaves the scrub column overhead drum and enters the main cryogenic heat exchanger (MCHE) where it is cooled down to about −160°C at which temperature the natural gas is a liquid at atmospheric pressure. The stream exits the MCHE and becomes the LNG product after running down to storage. The refrigerant for the MCHE is a mixture of mostly methane and ethane, which can be made up from the natural gas feed.

Several variations exist for the liquefaction process including nitrogen removal options on the back end of the plant (LNG typically has a maximum nitrogen specification of 1 percent), and processes are licensed by many companies. Such processes include cascade, dual mixed refrigerant (MR), single MR, and propane precooled among others. The differences in licensed processes are small with respect to thermodynamics and cost. The real key in selecting a liquefaction process is equipment selection and meeting the plant capacity goals.

The major equipment selections include MCHE type and compressor and driver. One process technology company uses a spiral wound type heat exchanger shown in Figure 5. Other licensed processes use plate fin heat exchangers shown in Figure 6. The plate fin exchangers tend to cost less than spiral wound but are more susceptible to leaks caused by thermal stress, and maintenance can be difficult if the plate fins are installed in a "cold box" insulation system where the exchangers are placed in a sheet metal box filled with perlite. Access to the exchangers is difficult because the insulation is similar to a white dust. The spiral wound exchanger can be maintained by access to the tube sheets by manhole or hand hole. The plant owner makes the choice of exchanger type based on these tradeoffs in addition to their own operating experiences.

Spiral Wound Exchanger
(Courtesy of Linde)

Schematic and photo (Courtesy of APCI)

Figure 5. Sketch and Photo of a Spiral Wound Heat Exchanger (SWHE).
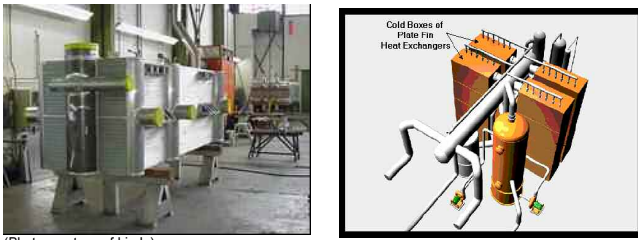

(Photo courtesy of Linde)

Figure 6. Photo and Schematic of a Typical Plate Fin Heat Exchanger (PFHE).

Compressor drivers in the past were typically steam turbines, but the trend today is gas turbines with a few trains driven by large electric motors with variable drive systems. The steam system costs more, adds equipment to the project, and takes more plot space; the authors' company expects the trend to continue along with a few motor driven compressor trains.

One other critical decision for the liquefaction plant is the cooling medium. Fresh water is not available at most liquefaction sites, and the usual choice is between once-through seawater and air cooling.

Pump Services

The major pump services in the liquefaction unit are:

• Amine circulation (acid gas removal process).

• Reflux for scrub column and fractionation towers (liquefaction process).

• LNG product pumps.

• Seawater pumps (if seawater cooled).

• Hot oil pumps.

The amine pumping service is often split into two parts: a low head pump working at high temperature followed by a high head pump operating at near-ambient temperature. Using the low head booster pump at the high temperature avoids problems with cavitation within the pump that would be present if the high head pumping were done at high temperature. The booster pump is typically a single-stage double suction pump with low net positive suction head (NPSH)) requirements. By using a pump with low NPSH requirements for the booster pump, the residual dissolved CO_2 remains in solution. When CO_2 is allowed to come out of solution, a phenomenon similar to cavitation occurs that is potentially very damaging to the pumps. To avoid the potential for cavitation damage, calculated NPSH available numbers are typically reduced by three to four times to provide sufficient actual margin. The amine circulation rate depends on the amount of acid gas, but a train making 5 MMTPA of LNG with a natural gas feed containing 15 percent CO_2 can have a circulation rate over 2000 m^3/hr handled with 3×50 percent pumps. The high-head circulation pumps are typically multistage, between-bearing, horizontal designs driven by electric motors.

The reflux pumps for the scrub column operate at about -30 to $-50°C$, and in the fractionation unit the de-ethanizer reflux pumps also operate at about $-30°C$. The flow rates of these pumps depend to a large extent on the natural gas composition. For a 5 MMTPA train handling associated gas the scrub column reflux flow can be in the 350 to 400 m^3/hr range, though a plant processing nonassociated gas usually has a smaller scrub column reflux pump. The scrub column reflux pump size depends to a great extent on the aromatics present, but in some cases where the natural gas contains little ethane and propane, recovering refrigerant components can be the main factor that determines reflux pump size. These pumps are normally single-stage.

The LNG product pump has a special design for cryogenic service. The pump is a submerged motor, "pot mounted" pump for these applications. Figure 7 shows an illustration of the pump that is mounted inside a container. The container, flooded with LNG during operation, also contains the motor. The suction of the pump is at the bottom of the container, and the LNG discharge flows through the motor thus providing cooling for the motor. There are no cryogenic rotating seals with this arrangement; the only seal needed is for the electrical connection box, and the box is always purged with nitrogen to prevent natural gas leakage through the conduit. This type of pump has the following advantages over conventional sealed pumps:
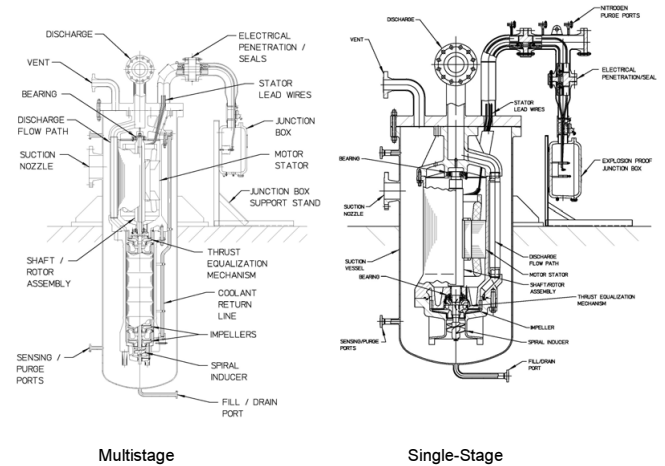

Multistage   Single-Stage
(Drawing courtesy of Ebara International Inc.)

Figure 7. Cryogenic Pump Cross Sections.

• Pump is completely submerged in the pumped fluid, resulting in reduced noise

• Does not contain rotating shaft seals that are difficult to design and maintain for the cryogenic temperatures. No leakage of flammable gas into the atmosphere. (The pump does have static seals in the electrical conduits to seal around the main power supply and instrumentation wiring.)

• Uses a single shaft design with both the pump impellers and motor on the same shaft, eliminating the need for a coupling and removing alignment issues

• Motor and pump bearings are product lubricated, eliminating the need for an external lube oil system.

• Explosion proof motor is not required

The operational and design challenges for a submerged motor LNG pump include the following:

• The suction pot of the pump must be liquid filled prior to starting the pump. Cool down of the pump is a delicate activity that must be done slowly to prevent excessive thermal stresses and damage within the pump. Various methods are used to try to ensure that the pump is properly cooled down and liquid filled prior to startup.

These include monitoring the temperature on a vent/bleed connection to the pump, use of temperature sensors within the pump suction container, and a level gauge on the suction pot.

● In a cryogenic application, condition monitoring is difficult since the vibration monitors need to be placed inside the cryogenic suction pot mounted on the pump. Some other options that have been used are external vibration instruments on the cover plate of the suction pot and operating without vibration instrumentation. These pumps have historically been very reliable, therefore for many users, operation without condition monitoring instrumentation has been an acceptable solution.

The seawater pumps are very large in a base load LNG plant and the pumps are mounted vertically in a seawater intake basin. The flow rates of these pumps are commonly in the 15,000 to 18,000 m³/hr range. Large, vertical, open pit, multistage pumps are commonly used. In some plants the seawater removes heat from a fresh water loop, instead of the more common once-through cooling where the seawater goes directly through heat exchangers and then discharges back to the sea. The fresh water loop circulation rate is similar to the seawater rate, but the liquefaction unit exchangers exchange heat with fresh water. The advantage of using the extra cooling loop is higher reliability and lower cost materials in the liquefaction unit. The disadvantages are extra cost and equipment for the fresh water loop and a higher heat sink temperature for the process (which makes the process slightly less efficient). Fresh water circulation pumps are normally horizontal, double suction designs.

The liquefaction process, in spite of being cryogenic, still requires some heating services. Examples are the amine stripper reboiler and fractionation reboilers. However, most gas turbine driven LNG plants do not have heat recovery steam generation (HRSG), and in such cases hot oil is a common heat transfer medium. The hot oil is circulated between the heat source and process services with hot oil pumps. In some cases steam is used as a heating medium, and in such cases condensate pumps and boiler feed water pumps replace the hot oil pump services. This substitution commonly takes place when there are enough sulfur compounds in the gas to make sulfur recovery in a Claus unit necessary; the Claus unit generates low pressure steam that is available for process heating services. Another option that has been successfully used is to incorporate a waste heat recovery unit in the exhaust of the gas turbine and utilize a heated water circuit for heating. The heated water system is maintained under pressure to prevent boiling, and a centrifugal pump is used for circulation. Hot oil and hot water circulation pumps can vary widely in design, but horizontal double suction designs are commonly used.

For a summary of the liquefaction pump services refer to Table 1.

Cryogenic Liquid Expanders

One other service in liquefaction related to pumps is the cryogenic liquid expander as an alternative to a Joule Thompson (JT) valve. The liquid expander (or hydraulic turbine) is like a pump running in reverse; the fluid enters at high pressure and exits at lower pressure, and shaft power is generated instead of being consumed. The drop in pressure is controlled with a back-pressure valve to prevent the discharge from flashing into two phases.

Two different technologies have been used for the cryogenic liquid expander application. The first is a submerged motor LNG pump operating as a liquid turbine. For this design, the expander/generator speed is controlled by using a Variable Speed Drive System (VSDS). This design has the advantages of the mechanical portions of the LNG cryogenic pumps, i.e., no seals and couplings.

The second approach is to use a liquid expander similar to a vertical turbine pump. This technology requires the use of a shaft seal (either dry gas or oil film) and an external generator. The performance of the turbine is controlled using a set of wicket gates (inlet guide vanes) to control the pressure drop across the expander.

Table 1. LNG Liquefaction Plant. Pump Services Based on 5 MMTPA Train (Typical Only).

Item	Capacity (m³/hr)	Head (meters)	Fluid	Pump Specifics	Comments
Lean Amine Booster Pump	500-1800	80-120	Amine	• Double Suction • Between Bearing • Radial Split Case • Single Stage	Capacity depends on solvent used and amount of acid gas present
Lean Amine Charge Pump	500-1800	600-750	Amine	• Multi-Stage – Volute Type • Between Bearing • Radial Split Case • Pressure lubricated sleeve and tilt-pad bearings	Dissolved CO₂ results in these pumps being susceptible to cavitation if not properly designed.
Scrub Column Reflux Pump	150-400	90-100	Hydrocarbon	• Cryogenic submerged motor type. • Vertical can type	Capacity depends on the amount of aromatics contained in natural gas
LNG Product Pump	1100 - 2000	150 - 240	Hydrocarbon (LNG)	• Cryogenic submerged motor type. (no seal or coupling)	-160 C operating temperature
LNG Loading Pumps	1350 – 2000	150 - 240	Hydrocarbon (LNG)	• Cryogenic submerged motor type. (no seal or coupling)	-160 C operating temperature
LNG Cargo Pumps	1350 – 2000	150 - 240	Hydrocarbon (LNG)	• Cryogenic submerged motor type. (no seal or coupling)	-160 C operating temperature
Seawater Pump	15,000-20,000	50-60	Seawater	• Vertical pump, AL-BR or duplex stainless steel material. • 10 – 15 meter shaft length	
Hot Oil Pump	1500-2000	120-140	Hot Oil	• Same as heated water pump.	
Heated Water Pump	750 - 1250	220 - 250	Heated Water	• Double Suction • Axial Split Case • Between Bearing	

The speed of the expander is fixed with the synchronous generator connected to the electrical grid.

The two examples of cryogenic liquid expanders are shown in Figures 8 and 9, and an actual installation is shown in Figure 10.

LNG STORAGE

The LNG product pump delivers liquid LNG to the LNG storage tanks. There are three common types of LNG storage tanks, known as "single containment," "double containment," and "full containment." In all cases there is secondary containment in the event of a spill, and the differences between the types are mostly in the method of secondary containment. Figure 11 shows drawings of the three types of storage. The single containment storage has a 9 percent nickel self-supporting inner tank and a carbon steel outer wall. There is perlite insulation between the two tanks. In the event of an inner tank leak, the outer wall may fail because carbon steel is not suitable to cryogenic temperatures. In this case secondary containment is provided by a dike surrounding the tank.

The double containment tank has a post-tensioned concrete outer wall capable of holding cryogenic materials, and no dike is needed because the outer wall provides the secondary containment. However the cold vapors contacting the roof may cause the roof to fail, thus the containment is not "full containment" because vapors may be released in the event of an inner tank leak.

The full containment tank is similar to double containment except that the roof is made of materials that can handle cryogenic temperatures; if the inner tank leaks, all liquids and vapors are still contained within the outer wall and roof.

The main advantage of the single containment tank is the low cost relative to the other storage types. The main disadvantage is that the impoundment basin requires more land, and providing enough distance between the dike and the plant fence to protect the public from heat and vapor dispersion requires even more land.
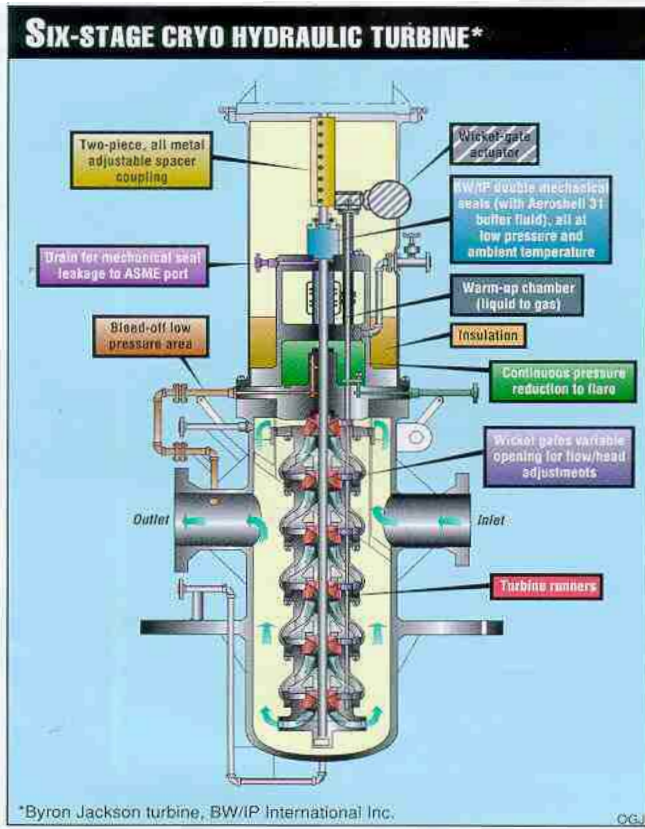
(Photo courtesy of Flowserve)

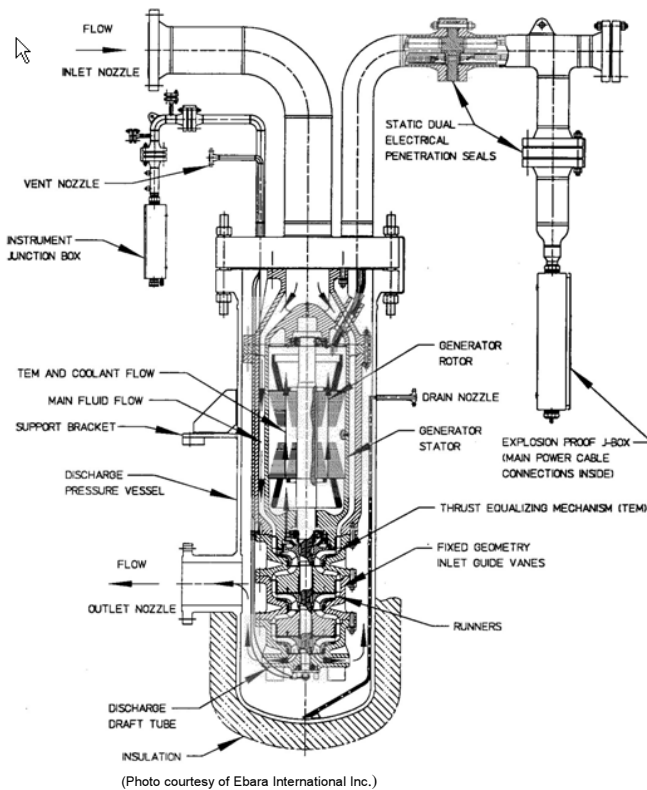*Figure 8. Schematic of Cryogenic Hydraulic Turbine (A).*

(Photo courtesy of Ebara International Inc.)

Figure 9. Schematic of Cryogenic Hydraulic Turbine (B).

The LNG loading in-tank pumps are similar to the LNG product pumps in that they are submersed in the LNG, but instead of a

(Photo courtesy of Flowserve)
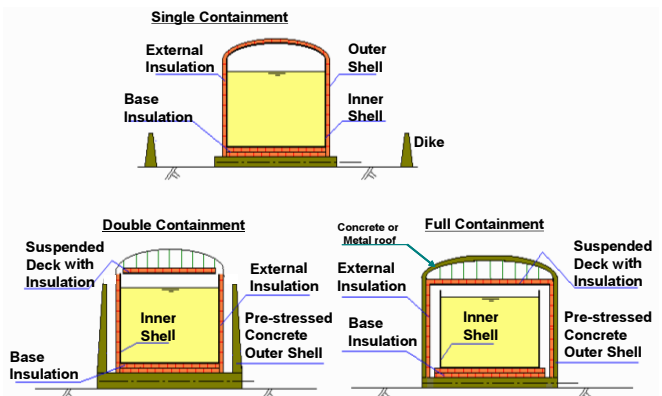
Figure 10. Hydraulic Turbine Removal.

Figure 11. Types of LNG Storage Tanks.

separate container the pumps are inside pump columns that extend to the storage tank roof, as shown in Figure 12. The key design feature of this pumping system is that it is possible to pull the pump for maintenance while continuing to operate the storage tank. There is a foot valve at the bottom of the column that prevents LNG from entering the column when the pump is pulled. The operators purge the column with nitrogen, and then remove the pump from the top of the column.

In-Tank Pump Process Objectives

The LNG loading pump capacities are usually based on filling a ship in 12 hours. The liquefaction plant typically has multiple storage tanks, and two to four pumps per tank. It is common to have a total of eight pumps running during loading, each with a capacity in the 1100 to 2000 m³/hr range and 150 to 240 meters of head. In many plants there is also a smaller pump in each tank in addition to the loading pumps. The purpose of this smaller pump is to recirculate LNG in the loading lines and stabilize the

(Photo courtesy of Ebara's Cryodynamics Division)

Figure 12. Column Mounted LNG Products Pump.

temperature when no ship is present. The loading lines are large diameter (24 to 36 inches) and must be kept cold between ship loadings because cooling them down is a long procedure.

In-Tank Pump Mechanical Design Features

The pumps used for the in-tank application are similar to the LNG product pumps except they are mounted in a column connected to the top of the tank instead of in a vessel. The pumps use submerged motors that are cooled by passing the LNG product flow past the windings of the motor. Special care must be taken when the pumps are removed from the tank because the winding insulation is very hydroscopic and will absorb moisture. Nitrogen purging of the pumps is required when they are not in use. The condition of the pumps is monitored by using accelerometers mounted on the pump housing close to the bearings. The pump bearings are typically a stainless steel material and lubricated by the LNG product. Reliability of the foot valve is as critical as the reliability of the pump. The foot valve is required to seal when the pump is removed to allow the tank to remain in service. The foot valve is supplied by the pump supplier as an integral part of the pump. The weight of the pump sitting on the foot valve causes the foot valve to open and allows LNG to enter the pump and column pipe.

LNG SHIPPING

LNG terminal layout and site selection are typically based on the following ship parameters:

● 130,000 to 135,000 m^3 capacity, having an overall length of up to 310 m, width of 46 m, and fully loaded draft of 11.6 m. The net delivery unloading rate into the receiving terminal is approximately 10,000 m^3/hr. There are smaller ships (down to less than 60,000 m^3), but the industry trend is toward larger ship sizes with designs on the drawing board for up to 250,000 m^3.

● 15 meters minimum water depth

The LNG ships have two different types of pumps. These are the large cargo pumps for transferring LNG, and the small spray pumps that provide LNG for the spray ring that helps keep the entire storage container in a cool state. The storage on the ship is usually one of two types, either self-supporting aluminum spheres or stainless steel membrane compartments supported by the ship hull. There are either four or five spheres or compartments, and each contains two cargo pumps and one spray pump. The cargo pumps usually have a capacity of 1200 to 1400 m^3/hr and the spray pumps have a capacity of 40 to 50 m^3/hr.

LNG RECEIVING TERMINALS

The LNG receiving terminal (sometimes called a "regas" facility) receives liquefied natural gas from LNG ships, stores the LNG in storage tanks, vaporizes the LNG, and then delivers the natural gas into a distribution pipeline. The receiving terminal is designed to deliver a specified gas rate into a distribution pipeline and to maintain a reserve capacity of LNG. The amount of reserve capacity depends on expected shipping delays, seasonal variations of supply and consumption, and strategic reserve requirements (strategic reserves are needed when the terminal may be called upon to replace another large source of gas from either a pipeline or another receiving terminal on short notice). A simplified process flow diagram is shown in Figure 13.
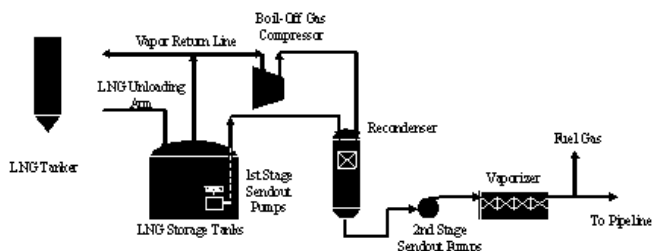

*Figure 13. Simplified LNG Receiving Terminal Process Flow Diagram.*

The LNG terminal consists of the following:

● *LNG unloading system, including jetty and berth*—LNG is transferred to the onshore LNG tanks by the ship pumps. The unloading facility is often designed to accommodate a wide range of tanker sizes from 75,000 m^3 to 135,000 m^3. It takes approximately 12 to 14 hours to unload one 135,000 m^3 ship. From the ship, the LNG flows through the unloading arms and the unloading lines into the storage tanks. The loading lines can be two parallel pipes, each 24 or 26 inch diameter or a single 30 inch or larger pipe.

● *LNG storage tanks*—Two or more above ground tanks are generally installed for receiving and storing LNG, though terminals have been built with a single tank. To reduce cost, designers try to minimize the number of tanks and maximize the amount of storage per tank. If the facility has only one tank, then sendout and LNG unloading will be from the same tank, but this does not cause any operating difficulties. The types of tanks are similar to the ones used for liquefaction facilities. The decision to use single, double, or full containment is based on cost, land availability, and sometimes protection from external events such as vapor cloud blast pressure, and missiles or small aircraft.

● *Vapor handling system*—During normal operation, boil-off vapor is produced in the tanks and liquid-filled lines by heat transfer from the surroundings. This vapor is collected in the boil-off header that ties into the boil-off compressor suction drum. A boil-off gas (BOG) recondenser may also be provided, which serves to recover the BOG as product and provides surge capacity for the LNG second stage pumps. During ship unloading, the quantity of vapor in the tank outlet increases significantly.

During upset, extreme turndown, or emergency conditions, vapors may be generated within the terminal that exceed the capacity of the BOG and pipeline compressor. If this occurs the vapors vent to the atmosphere through an elevated vent stack or a flare for safe disposal. In the case of a vent stack the vapors are preheated if necessary to avoid flammable mixtures near ground level.

● *LNG vaporizers*—LNG terminal facilities have multiple parallel operating vaporizers with spares. Open rack vaporizers (ORV) are common worldwide (although they are not used much

in the US terminals to date) and use seawater to heat and vaporize the LNG. The submerged combustion vaporizer (SCV) uses sendout gas as fuel for the combustion that provides vaporizing heat. Because of the seawater system cost, the ORVs tend to have a higher installed capital cost while the SCVs have a higher operating cost because of the fuel charge. At many facilities the best economics are achieved by using ORVs for normal send out and SCVs as spares.

Other site factors also impact the decision of whether to use ORVs or SCVs. If the seawater temperature is below 42°F, ORVs are usually not practical because of seawater freezing. At some sites, it is not practical to separate the seawater discharge from the seawater inlet, and SCVs must be installed to avoid recirculation problems. The submerged combustion vaporizers also have environmental issues because of nitrous oxide (NOx) emissions and the water combustion product that requires treating before discharge.

● *Open rack vaporizers*—Seawater in an open falling film type arrangement vaporizes LNG passing through the tubes (Figure 14). The water falls over aluminum panels and collects in a trough before discharging back to the sea. The seawater first passes through a series of screens to remove debris before entering the intake basin. Raked bar screens provided in the inlet of the intake basin remove floating debris and provide protection for the vertical seawater and firewater pumps in the basin. The pumps are located in individual bays within the intake basin. At the inlet of each seawater pump bay, a traveling band screen may be provided for further removal of suspended solids to prevent blockage or damage to the open rack vaporizers. The larger, single ORV units installed are for a gas sendout rate of approximately 200 to 250 MMSCFD.
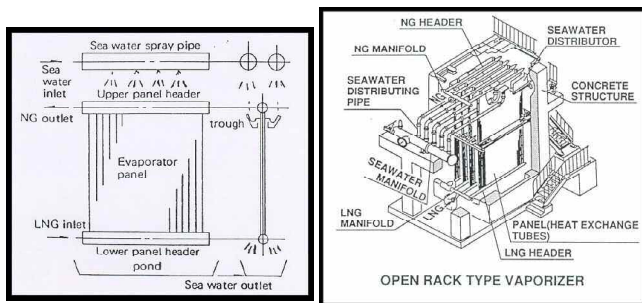
(Drawings courtesy of Kobe Steel, Ltd.)

Figure 14. Open Rack Vaporizer.

● *Submerged combustion vaporizers*—These vaporizers burn the natural gas taken from the sendout gas stream and pass the hot combustion gases into a water bath that contains the heating tubes for LNG (Figure 15). The largest single SCV units installed are for a gas sendout rate of approximately 150 MMSCFD.
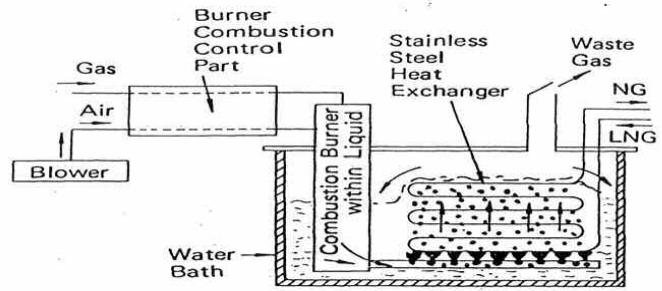

Figure 15. Submerged Combustion Vaporizer.

● *First stage sendout pumps*—Several low-head LNG sendout pumps are installed in each LNG storage tank. These pumps are similar to the loading pumps at the LNG liquefaction facility, except the sendout rate is much lower than the loading rate therefore the pumps are smaller. A very large receiving terminal will have a sendout rate of 2 billion standard cubic feet per day (BSCFD) while the ship unloading rate is closer to 5 BSCFD. The discharge pressure of the first stage sendout pumps is around 8 barg.

● *Second stage sendout pumps*—The sendout gas is usually injected into a high pressure gas distribution system of approximately 80 barg. For this pressure, multistaged sendout pumps (booster pumps) are required. The pumps are high-head and take LNG from the first stage pump discharge and boost up the pressure to the vaporizers at the required pipeline pressure.

Receiving terminals to date are expected to operate close to 365 days per year and have spared equipment to achieve this availability. In at least one case, a terminal operated over three years continuously and was shutdown only for a statutory inspection. In light of the traditionally high terminal availability, spare equipment can be eliminated and cost savings achieved if the gas consumers can tolerate interruptions in the sendout supply.

CONCLUSIONS

The LNG industry continues to change as companies with gas reserves compete to supply markets. In this arena achieving low cost per ton of LNG and high reliability makes the product attractive, and improving economy of scale with larger plants and equipment continues to enhance plant economics. It is this reality that is driving the technology forward. At the same time, the LNG industry is based on converting a gas that has to be compressed for pipeline transport into a liquid that can be pumped for transport by ship; pumps will continue to play an indispensable role. With a good understanding of the basic LNG chain and the forces driving innovation, the pump manufacturers and rotating equipment engineers will be able to anticipate and respond to industry demands in a manner that provides high value for their customers.