LNG TECHNOLOGY FOR THE COMMERCIALLY MINDED

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ABSTRACT

As the LNG industry continues to grow there is a steady influx of new players in the business. Most would classify themselves as technical or commercial with respect to their primary responsibilities, and for better or for worse, most have little exposure to the other discipline. Thus, there are process engineers with little understanding of the financial terms and conditions of a project, and commercial people who may understand technical aspects of their specific project but may not be aware of other available processing options.

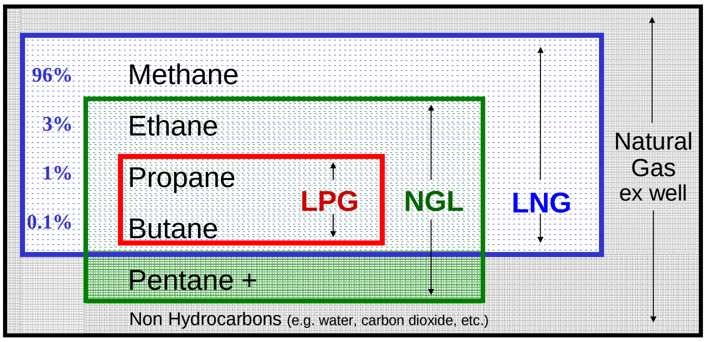
The purpose of this paper is to provide a basic technical understanding of the LNG route of gas monetization, but for the commercially minded. It is one thing to say that one technical solution is less costly than another, but what is the impact on the ability to finance the project, or the ability to sell the product? It is our goal to clarify some of today's technical solutions and expected trends for the future, in a way that relates to someone with a commercial background. This clarification will be based on the definition of an LNG train, which is one continuous processing unit that condenses natural gas from a gaseous state to a liquid state.

Some key technology issues identified and addressed in this paper are noted below:

- GTL and LNG – How they are different, and how they are the same
- Putting train size in perspective
    1. LNG Train Size – Economy of Scale
    2. LNG Process Drivers and Compressors – What are the limits?
    3. Electric Motor versus Gas Turbines for Refrigerant Compressor Drivers – What is behind this comparison?
    4. Ships – What is on the drawing board and how does this impact receiving terminal design?
- Environmental challenges – What is the real impact of tighter regulations?
- Safety – What are the measures taken to protect the public?
- Offshore vs. Onshore
- Product Specifications
    1. Associated Gas vs. Non Associated Gas
    2. Ethane/Propane Extraction – Should these facilities be on the liquefaction or receiving end?

I. Introduction

Growth of the liquefied natural gas (LNG) industry has propelled this niche market into the mainstream of the natural gas business. So what exactly is LNG? Below is a simplified schematic of LNG in relation to gaseous products.



LPG – Liquid Petroleum Gas
NGL – Natural Gas Liquids
LNG – Liquid Natural Gas

Figure 1 Terminology and Constituents – Natural Gas and its Liquid Products

The major obstacle in marketing natural gas is the large volume of the gas at ambient temperature and atmospheric pressure. As a result natural gas is seldom transported at such conditions. The most convenient method of transporting gas is at high pressure in a pipeline if the distances are short. The general rule of thumb is that pipeline versus LNG transport economics break even at approximately 3200 km onshore and 1600 km for offshore. At distances greater than these LNG is usually more attractive economically, as shown in Figure 2.

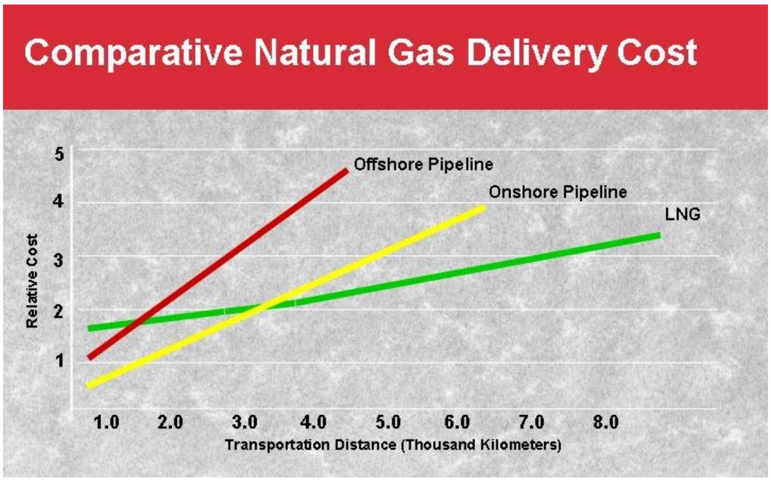


Figure 2 LNG economics improve as distance to market grows [Ref. 1]

Chilling natural gas down to -160°C where the gas becomes a liquid reduces the volume by a factor of roughly 600. This volume reduction is what has made LNG the method of choice for transportation over long distances. However, the low temperature is a disadvantage for several reasons. First is the fact that reducing the temperature of the gas to -160°C requires energy and expensive processing equipment. Typically about 10% of the natural gas entering the plant must be burned to provide the energy needed for refrigeration. There are ways to make processing more efficient as will be discussed later, but the energy needed is still substantial and the refrigeration machinery is expensive.

Secondly, low temperature processing requires special materials. Pipelines operating at ambient temperature can be made of carbon steel, while LNG must be stored in aluminum, stainless steel, high nickel steel, or other more expensive materials. Recent current prices for carbon steel are about $0.50/lb while 304 SS (stainless steel) is about $2.30/lb. Thus, the product storage and transportation costs are relatively high for LNG compared to transportation of other liquid hydrocarbon products such as diesel or gasoline.

II. Gas Monetization Options

There is a high level of interest in ambient temperature transportation methods such as gas-to-liquids (GTL) (conversion of natural gas into LPG, naphtha, diesel, and gas oil products), not only because of the relative ease in handling ambient temperature liquids, but also because there is a larger product market capacity versus LNG . A world scale LNG plant making 10 million metric tons per year (MTPA) might contribute 6% to the total LNG world market; however, a GTL project handling the same amount of gas will add only a 0.3% increment to the total world liquid fuels market.

GTL technology is completely different from LNG, yet GTL projects still have much in common with LNG. Both technologies are based on getting a remote gas to market and involve large, complex projects in difficult locations.

In LNG production, natural gas does not go through any chemical reactions; rather, the gas only changes from gas to liquid. In GTL production, the natural gas goes through three process steps, each involving a chemical reaction as shown in Figure 3.

In summary, in the first step, methane (which contains a single carbon with four hydrogens) splits, with the addition of oxygen, into carbon monoxide and hydrogen. In the second step this carbon monoxide and hydrogen is then recombined to form long chains of carbons connected to each other. However the long chains that are formed are too long to use as a practical fuel- it is more like a wax. Hence the third and final step is to break the long chains of carbons into a more practical number of chains such as for diesel (11-19 carbons).

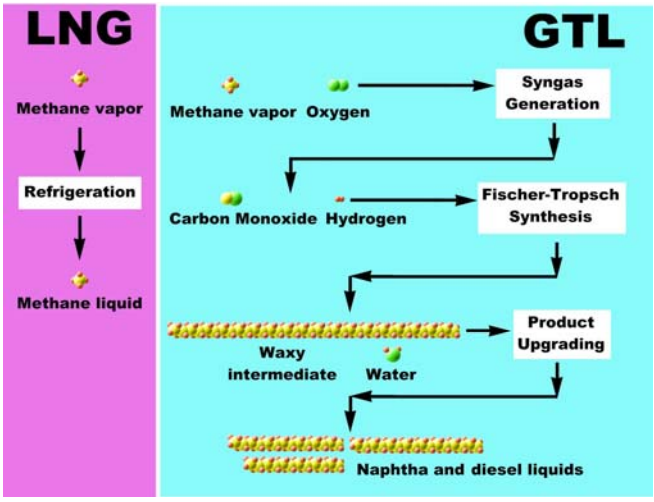


Figure 3 Simplified GTL Chemistry

Typical project capital cost numbers are approximately $200 per metric ton per year of LNG product and $500 per ton per year of GTL product, although these figures are both highly variable depending on project scope and site. In terms of heating value, these convert to capital costs of approximately $3.88 per MMBTU per year of LNG product and $11.00 per MMBTU per year of GTL product. Hence the higher initial cost of GTL production compared to LNG must be compensated for by the lower shipping and terminal costs for GTL. Because of the special materials needed to handle cryogenic LNG, the transportation costs for LNG are higher than for GTL. An LNG tanker with 135,000 m^3 capacity costs about $170 MM while a GTL carrier of the same size costs about $55.2 MM.

III. LNG and Economy of Scale

The first baseload LNG train built in Arzew, Algeria in 1964 had a capacity of 0.4 MTPA. Since that time, the single train capacity has grown beyond 5 MTPA and at least one project is now nearing the engineering, procurement and construction (EPC) phase based on 7.8 MTPA. Figure 4 below shows the trend of greater train capacity over time.

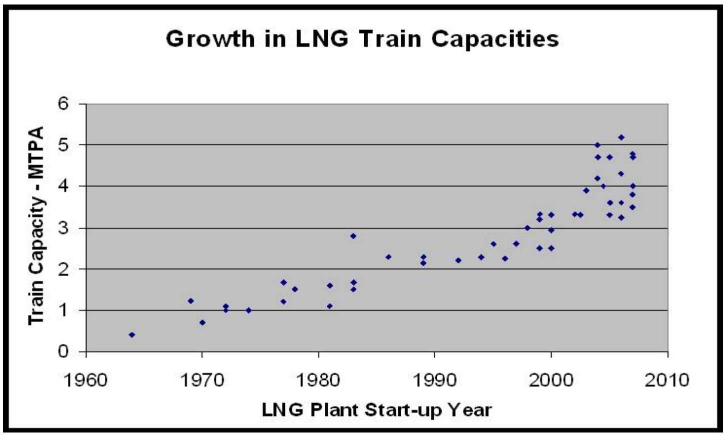


Figure 4 Trend of LNG Train Capacities Over Time

The reason for the trend towards greater train size is economy of scale. Figure 5 below shows a typical cost breakdown for an LNG liquefaction plant. Although the actual breakdown depends on site, much of the cost will always be in the storage and loading area.

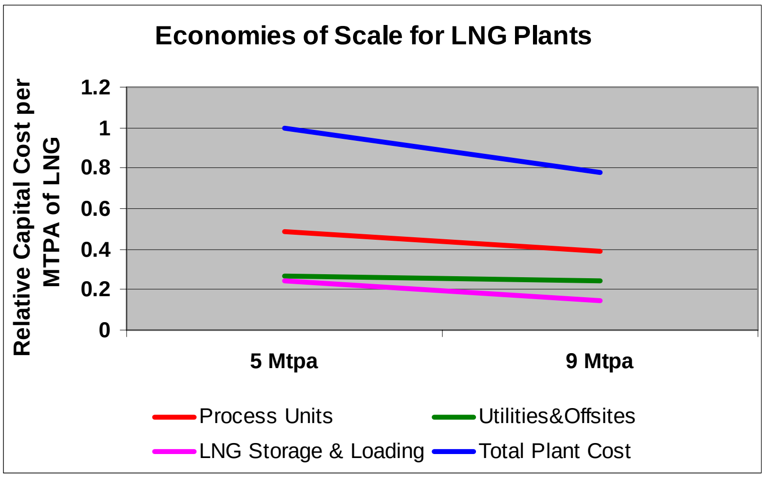


Figure 5 Approximate LNG Plant Cost Allocation

The size of storage and loading facilities depends to some extent on the plant capacity, but typically has a greater dependence on ship size. All things being equal, a plant making more LNG will have more frequent ship loadings, but the product loading rate remains the same, and storage capacity will only increase slightly. The ability to increase train capacity while maintaining constant storage and loading size improves the overall economics.

The cost difference between a single train and two smaller trains is substantial. The LNG train typically represents 50% of the total facility cost for a single train facility. If the train is split into two parallel units the train cost increases by about 35-40% which increases the total facility cost by 17-20%.

Splitting process units into multiple trains is sometimes done to reduce the impact on production when a single unit goes down. Production is either 0% or 100% in a single train unit while a two-train unit usually functions at 50% or 100%. Only in extremely rare cases will the production for the two-train unit be 0%.

At the same time it is important to realize that overall availability remains the same. The reason is that in a two-train unit a single failure reduces production by 50%, but there are twice as many items to fail. Production is nearly the same over the long run whether the plant is single train or multiple trains.

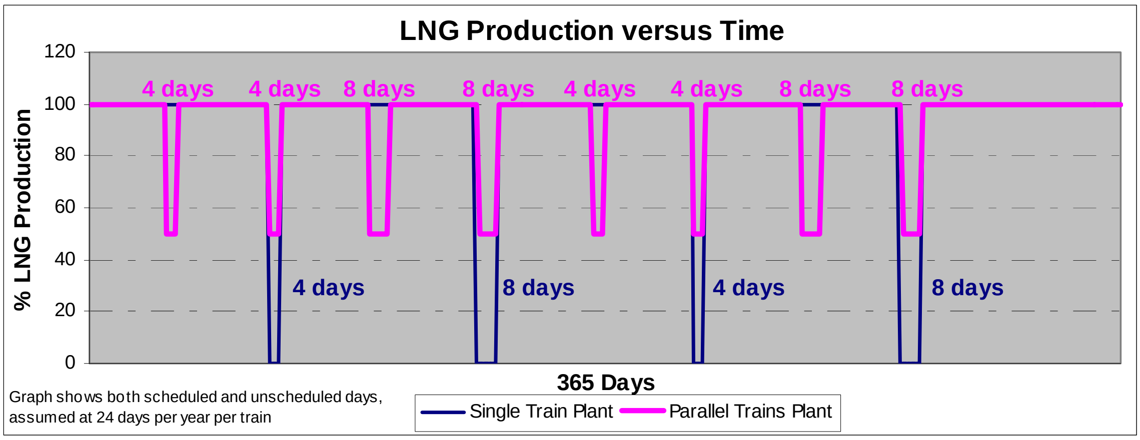


Figure 6 Single and Multiple Train Availability

Equipment developments have, for the most part, kept pace with the increases in train capacity. Equipment selection trends also indicate changes in philosophy that extend beyond a mere response to capacity increases. These trends are discussed further as follows:

A. Steam Turbines vs. Gas Turbines

Most of the earlier plants were steam turbine driven, though there were some exceptions. Steam turbines do have some advantages over gas turbines, such as providing a designer the ability to design over wide ranges of power and speed. Gas turbines on the other hand, come in discrete sizes such as "Frame 5" and "Frame 6". Steam turbines, unlike gas turbines, can run for years and years without scheduled maintenance.

There is an unmistakable trend toward gas turbines for a variety of reasons as discussed below.

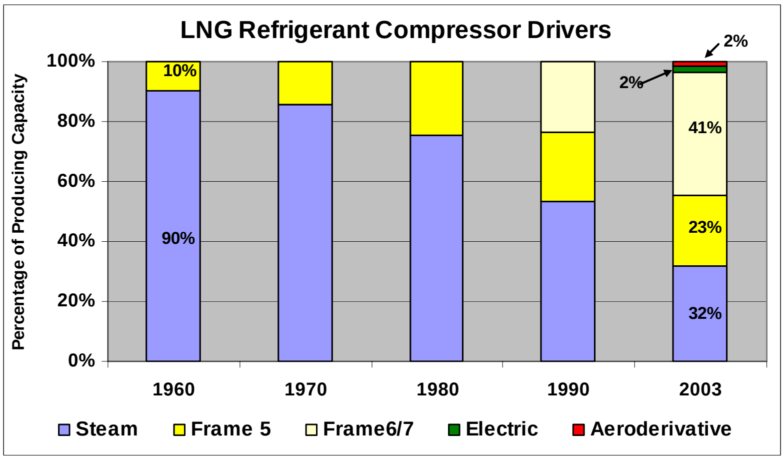


Figure 7 Trends in LNG Refrigerant Compressor Drivers

1. Cost

Capital equipment cost savings for a gas driven/air cooled plant average 7%. This savings is further increased for the plant total installed costs (TIC) to 14-15% when the seawater system civil installations (typical for steam driven plants) are included.

Fuel consumption also drops by almost 8% with the gas driver/air cooled plant thus reducing ongoing operation costs.

2. Equipment Count

Steam drivers add to equipment count in a major way, as shown in Table 1. The table indicates the number of items needed in a steam driven plant beyond those needed for gas turbine drivers.

Table 1 Equipment Count Additions for Steam Turbine Drivers (per train)

System	Additional Equipment Items
Heat Exchangers (Surface Condensers)	5
Seawater Distillation	16
Steam	17
Condensate Handling and Treatment	52
Total	90

The additional 90 items are significant considering that a gas turbine driven train typically has about 140 items. Furthermore, if a seawater system is installed instead of air cooling another 64 items are needed. A steam driven plant requires more operating attention and maintenance effort which also contributes to the trend towards air cooling shown in Figure 8.

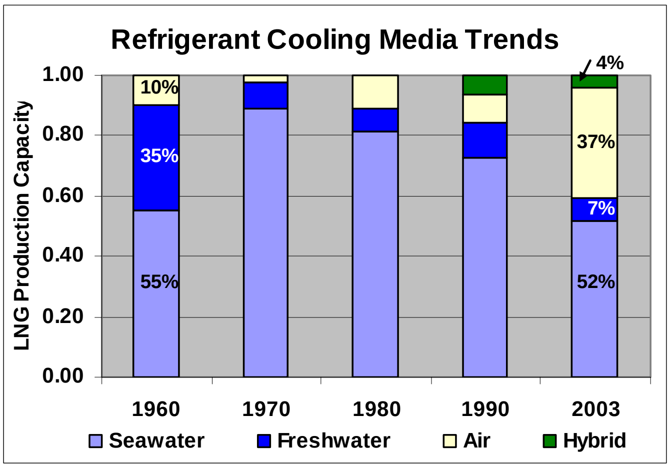
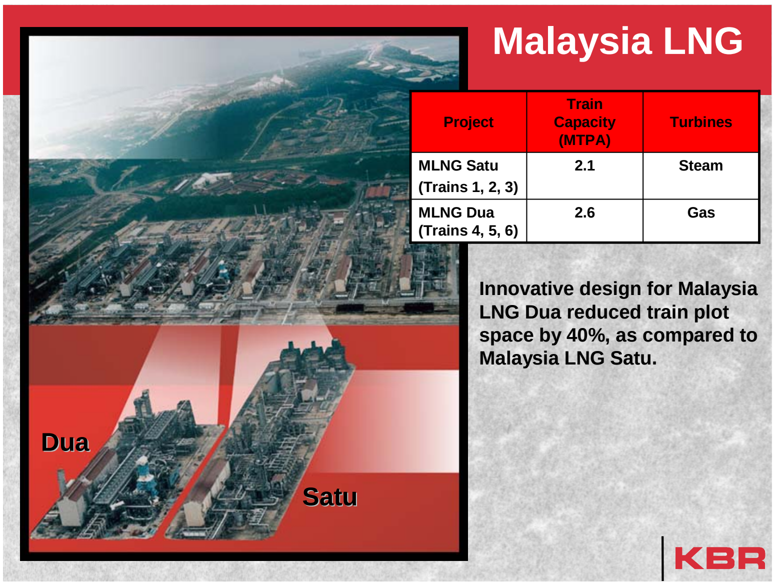


Figure 8 Trends in Refrigerant Cooling for LNG Plants

3.   Plot Space

The new generation of gas turbine driven LNG plants require a smaller foot print than steam driven plants as shown in the figure below.



Malaysia LNG

Project	Train Capacity (MTPA)	Turbines
MLNG Satu (Trains 1, 2, 3)	2.1	Steam
MLNG Dua (Trains 4, 5, 6)	2.6	Gas

Innovative design for Malaysia LNG Dua reduced train plot space by 40%, as compared to Malaysia LNG Satu.

Figure 9 Turbine Driver Selection and Effect on Plot Area for LNG Production Facilities
Source: Photos courtesy of Malaysia LNG Sdn. Bhd. and Malaysia LNG Dua Sdn. Bhd.

B. Electric Motor Driven Plants

In recent years, there has been increasing interest in using electric motors as drivers for the refrigeration compressors. Electric motor drivers in world-scale LNG plants can increase plant availability by about 3-4%. This option can require about $90-100 MM additional investment for a 3.5% increase in annual production (315,000 TPA for 9 MTPA plant).

The Snohvit project in Norway will be the first LNG plant to have motor drivers. The site is unusual (for an LNG Project) in that there is access to the national power grid. Nonetheless, to achieve maximum reliability, the plant is designed to be self-sufficient and will generate its own power during normal operation.

C. Main Cryogenic Heat Exchangers

Basically there are two styles of main cryogenic heat exchangers (MCHE) used in liquefaction processes: spiral (or coil) wound exchangers (SWHE) in a pressurized shell or plate-fin (also known as brazed aluminum) (PFHE) in cold boxes. The style of exchangers is related to the type of liquefaction process employed, but ultimately the selection is by the plant owner.

There is little difference in cost and schedule between most liquefaction processes. The heat exchange equipment is a small portion of the overall cost, and the process drivers are not tied to a specific process (for example, GE Frame 5 and Frame 7 gas turbines can be employed in all commercial liquefaction processes). As long as the process efficiencies are similar the overall costs will also be similar and the selection of process is an exercise in matching equipment selections with capacity targets.

D. Storage

There are several different types of storage tanks to choose from, including single, double, full containment, and in ground membrane type storage. The decision of which to use is often based on land availability. All LNG storage types have secondary spill containment and the primary difference between single, double, and full containment is the secondary containment. The single containment tank has a dike for secondary containment and this type of tank requires the most land.

The double containment tank has an outer concrete wall for secondary containment, and therefore requires less land. The full containment tank is similar to the double containment but also has a roof that is capable of handling cryogenic temperatures, and contains not only the liquid spill but also vapor. Figure 10 below shows the cost factors and schedule requirements for each type; however, the cost factors do not take into account the cost of the land or dikes. Hence, including these factors may alter the overall cost relationships. The table also shows a PC-PC type of tank which is a double concrete tank design that has yet to be installed in a baseload facility.

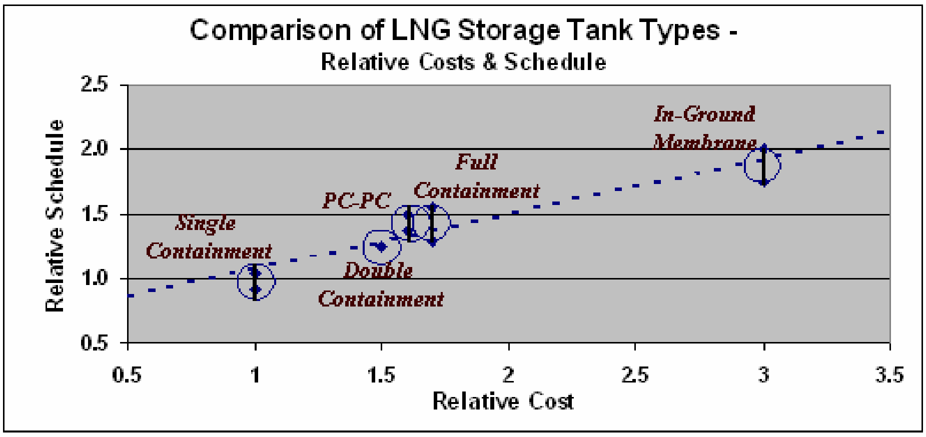


Figure 10 Relative Costs and Schedule Impacts of Various LNG Storage Tank Types

A facility with 2 x 160,000 m^3 tanks requires about 220-250 acres of land if the tanks are single containment. Most of this land is not needed for the storage and containment, but the land is needed to comply with thermal radiation limits at the plant fence line. For the same criteria full containment storage requires only 70-80 acres of land, based on a collapsed roof scenario. However, at many locations the governing authorities do not consider a full containment roof failure a credible scenario and in such cases an entire receiving terminal can fit within a 25 acre plot. See Figure 11 for a graphical representation of these indicative single and full containment plot requirements.

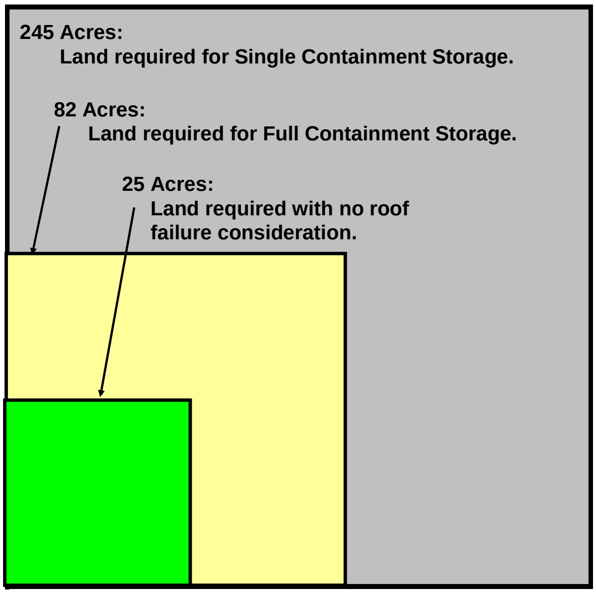


Figure 11 Indicative Plot Requirements Based on Thermal Radiation Criteria

Like other equipment in the LNG industry, storage tank capacities have grown. The plot below (Figure 12) shows storage tank size over time for LNG plants worldwide. Tank sizes of 140,000-160,000 m^3 are now common, and trending to capacities up to 200,000 m^3.

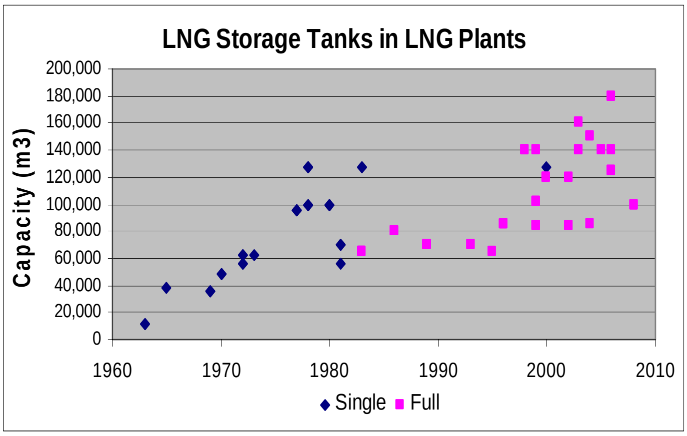


Figure 12 Trends in LNG Storage Tank Capacities

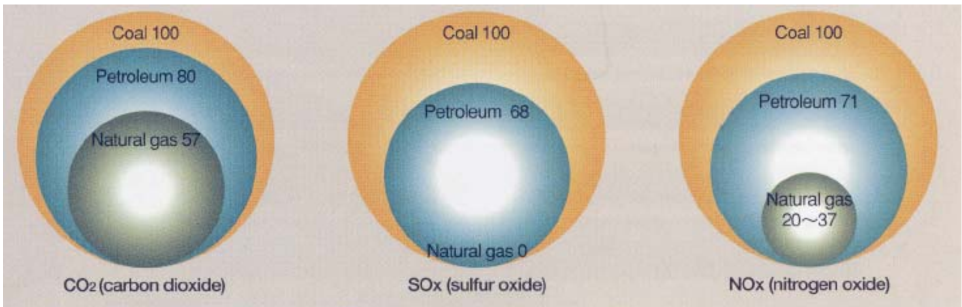
E. Shipping

As with the LNG liquefaction plants and storage tanks, LNG ships have also grown in size. In the last ten years the typical size has grown from 125,000 m^3 to 145,000 m^3, and sizes of 200,000 m^3 to 250,000 m^3 are currently proposed by ExxonMobil. Larger sizes improve economy of scale, but questions remain on whether today's marine facilities can receive the larger ships and if so, the extent of modifications to existing terminals that might be required.

Many facilities can be modified for relatively low cost, but the key variable is water depth. If the water depth is not sufficient the cost jumps by an amount that depends on the marine contours and conditions and site location, and in such cases the cost can have a measurable economic effect.

IV. Environmental Challenges

Reducing environmental impact is one of the main drivers for growth of the LNG industry. Burning natural gas is much cleaner than burning coal or liquid petroleum products. Figure 13 below shows a comparison of CO_2, SOx and NOx emissions for the three different fuels. In all three categories natural gas has the clear advantage. This and the strong global growth in electric power generation explain much of the steady growth in natural gas and LNG demand over the years.



[Ref 4]

Figure 13 Comparison of emissions of by-products of fossil fuel combustion

Reducing the environmental impact of the LNG plant itself is also a concern. The LNG plant has vapor emissions from process vents and driver exhausts, liquid effluents from sumps and drains and cooling medium return, and solid waste from spent molecular sieve and mercury removal catalyst. Compared to other chemical processes the LNG plant is relatively clean with few hazardous materials. Still, the industry strives to reduce environmental impact by applying one or more of the following methods:

- To reduce fuel consumption, use combined cycle power wherein the gas turbine exhaust heat generates steam for power generation (See Figure 14).

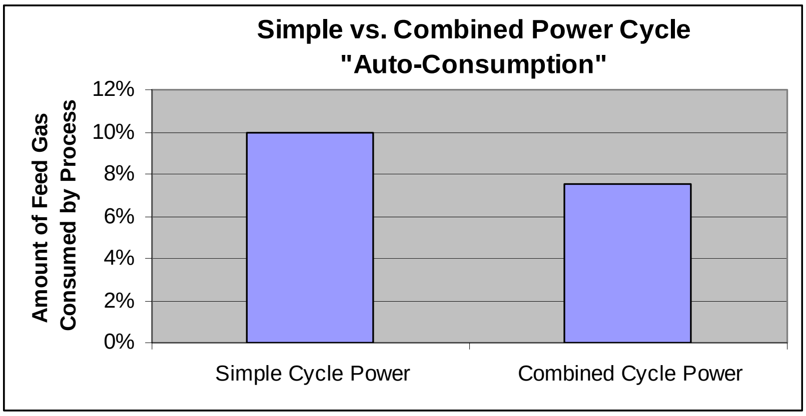


Figure 14 Simple Cycle vs. Combined Cycle Power

- Use dry low NOx (DLN) burners in gas turbines. The large Frame 7 gas turbines without DLN generate about 150-160 PPM of NOx in the exhaust gas, and the smaller Frame 5's generate about 125 ppm. With DLN burners the NOx drops to 25 ppm for both types of gas turbines. Frame 7 gas turbines now come with DLN as a standard accessory (ordering without DLN will save little if any cost). For the smaller Frame 5 gas turbines DLN remains an option.

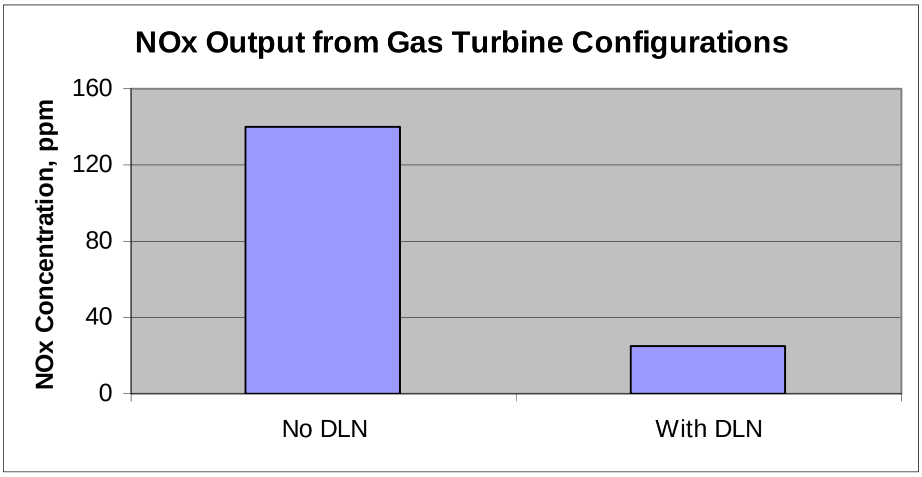


Figure 15 NOx Reduction with DLN Burners

- Consider air cooling instead of seawater cooling to avoid any impact on marine life. Designing the seawater system to World Bank guidelines minimizes impact on the marine environment, but in some cases selecting air cooling speeds up the approval process. Also, for many sites air cooling will be a less expensive option.

V. Safety

Safety is such a significant topic that it would be possible to make different aspects of safety the subject of every paper in this conference. For the sake of brevity this discussion will cover safety only at the highest level. At the same time it must be mentioned that safety in the design, construction, and operation of LNG facilities is a key focus area for all involved, as safety is a core value.

The main safety objectives when designing an LNG facility are:

- Protect the general public
- Protect the plant personnel
- Limit the extent of property loss in the event of a hydrocarbon spill

All of these objectives are achieved while considering that a cryogenic hydrocarbon spill vaporizes and the cloud expands as the spill is warmed by the surrounding environment. The measures used to avoid spills and to mitigate the consequences when they occur are shown in Figure 16.

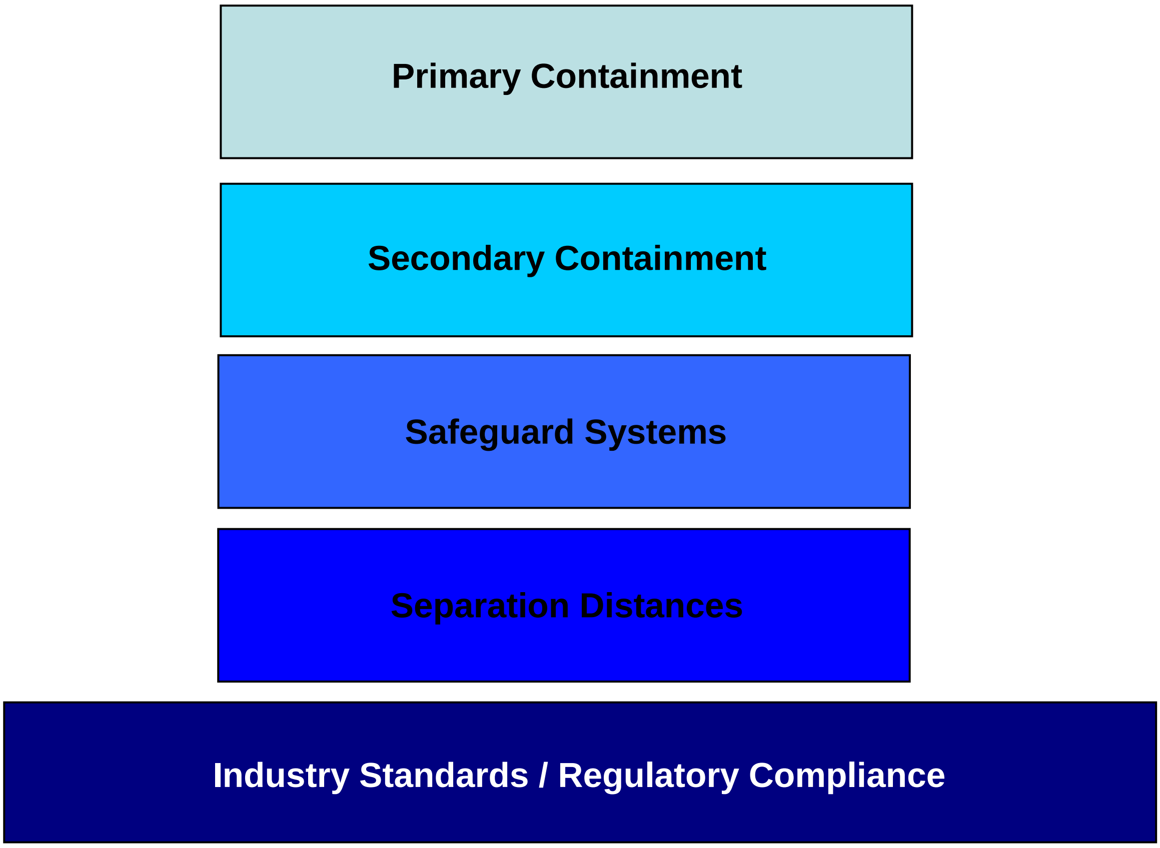


Figure 16 LNG Safety Measures

- Primary Containment
  - First and most important safety requirement
  - Achieve by employing suitable materials for storage tanks and other equipment, and by appropriate engineering design throughout
- Secondary Containment
  - Ensure that if leaks or spills occur, the LNG can be contained and isolated.
  - For onshore – dikes and berms, or reinforced concrete tanks around inner tanks
- Safeguard Systems
  - Minimize releases of LNG and mitigate effects of release - both active and passive systems
  - Use gas, liquid and fire detection to rapidly identify any breach in containment
  - Use remote automatic shut off systems to minimize leaks and spills in case of failures
- Separation Distances
  - Minimum distances between equipment and the plant fence line based on thermal radiation, vapor dispersion, and blast pressure criteria
  - Codes and regulations siting facilities at a safe distance from adjacent industrial areas, communities and other public areas
- Industry Standards/Regulatory Compliance

VI. Offshore LNG

Offshore LNG options are currently under development, though none are commercialized as of this writing (however Exelerate Energy is on track to come on line on the US Gulf Coast by the time this paper is published). The offshore technology solution might be cost effective for liquefaction if getting the gas to shore requires long pipelines in deep water. On the receiving end the offshore option looks attractive in cases where land is difficult to acquire or where local opposition could delay or stop an onshore development.

Generally speaking an offshore LNG facility costs significantly more than the same facility installed onshore. Yet some onshore sites are difficult or expensive because of long jetties or breakwater requirements (which can add over $100 MM to the cost of some sites). In such cases the penalty for moving from onshore to offshore may not be too severe.

VII. Product Specifications

Natural gas is primarily methane, with some ethane, propane, butane and heavier hydrocarbons. The relative amounts of these heavier components have an effect on the natural gas properties, namely heating value (HHV) and Wobbe Index (WI). The heating value is a measure of the combustion heat available for a given amount of gas molecules. The Wobbe Index is a relative measure of how much heat will be provided through a burner tip at a fixed pressure. More heavies result in higher heating value and higher Wobbe Index.

The globalization of natural gas is a positive development for the LNG industry since baseload LNG is traded internationally. But this development is also leading to product specification problems related to "gas interchangeability." When gas is produced for a local market the specifications can be anything because the gas consumers will have equipment and appliances designed for that local specification. However, when that same gas is exported to a different consumer market, the specifications may not be consistent.

This is the case with the European, Pacific Rim, UK and US markets as shown below in Figure 17. The wide differences in the specifications lead to legitimate concerns on everything from power generation difficulties to catching the chef's apron on fire. In other words, the gas going to one market is not interchangeable with the gas going to another market, especially if one is targeting both the Pacific Rim and US markets.

In the absence of gas conditioning, the LNG product is close in composition to the gas entering the plant. The gas can come from two sources: associated and non-associated. Associated gas is released during oil production when the oil drops in pressure as it leaves the well. Associated gas has a high concentration of heavy components and must have propane and butane (also known as liquid petroleum gas, LPG) extracted to meet most, if not all, natural gas specifications globally.

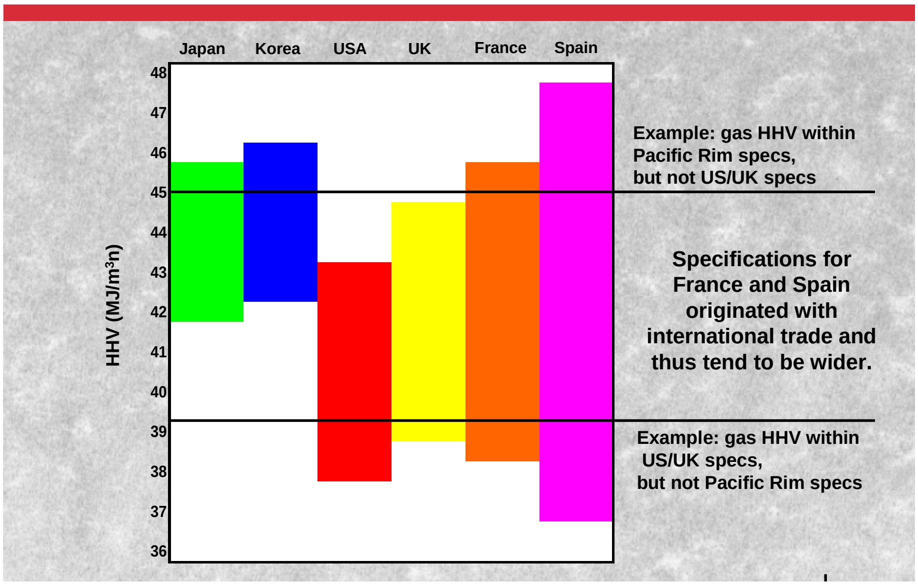


Figure 17 Gas Interchangeability

With the broad European specifications and large Pacific Rim market, gas interchangeability has not been a big issue until recently. With the expected growth in UK and US markets the industry now has to grapple with interchangeability. Options include LPG extraction or injection at the liquefaction or receiving end, or injection of an inert gas such as nitrogen at the receiving end.

For the time being, the industry is heading in a direction of conditioning the gas at the receiving end. This provides the receiving terminal with more relatively inexpensive options for LNG supply. However on the liquefaction end, some owners are looking into LPG injection based on a long term supply agreement of sufficient size to justify the effort. Although gas interchangeability is important from gas marketing and technology perspectives, the cost of providing interchangeability is relatively low and it is probable that there will be no single industry answer. Some liquefaction plants will have the flexibility built in and some will not, and the same will be true on the receiving end.

VIII. Summary

LNG continues to be an attractive means for monetizing remote gas reserves, and the future appears bright as manufacturers continue to improve technology and reduce LNG costs. The industry has been responsive to environmental and safety concerns of the societies it serves, and continues to lead the way in developing health, safety, and environmental practices. It will be interesting to watch and participate in the immediate future of LNG as the industry addresses onshore/offshore and gas interchangeability issues to increase natural gas trade on a global basis.

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