Abstract
As the LNG industry accelerates its growth, there is a steady influx of new players. Most would classify themselves as either technical or commercial with respect to their responsibilities, with limited exposure to the other discipline. Thus there are engineers with little understanding of the financial terms and conditions of a project, and financiers who may have a limited understanding of the technical aspects of their specific project and yet may not be aware of the other paths that might have been taken.

The purpose of this paper is to provide a basic technical understanding of the LNG route to gas monetization, which would be of interest to someone with a commercial interest. It is one thing to say that one technical solution is less costly than another, but what is the impact on 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.

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

- LNG Train Size – What is being done to make larger trains
- Why are LNG plant costs rising?
- Site issues
  - Construction issues
  - Environment and emissions
  - Cooling medium: air versus sea water
  - Cold climate applications
- Offshore vs. Onshore
  - When will offshore LNG be the answer?
  - What are the possibilities for processing both offshore and onshore?
- Proven design and Technology Innovations:
  - Proven execution methods
  - Successful risk management
  - Continued improvements in plant design/fabrication
  - Improved reliability/ease of operation
  - Improving efficiency in a cost effective manner
I. Introduction

For the technically minded, “LNG Technology” represents unique engineering solutions that implement and in many cases push the limits of capacity and functionality of LNG production plants. However, LNG Technology encompasses much more than engineering solutions. LNG Technology is the culmination of know-how that enables people to develop complex infrastructure projects in challenging locations; these projects monetize natural gas assets through equally complex commercial arrangements. Therefore, LNG technology includes areas such as contracting strategies, cost estimation, unique project alternatives (e.g. GTL or offshore LNG), and optimizing the use of material and human resources.

For GASTECH 2005, the paper LNG Technology for the Commercially Minded discussed some key technical issues, for the benefit of a commercial audience. The technical evolution of the LNG industry can be highlighted by rules of thumb, trends over time, and technical or economic comparisons. The areas of discussion included the growth of LNG train capacities, trends of LNG-related equipment, and the challenges of LNG product specifications. These technical issues are still relevant for today's LNG projects.

In this global environment, it takes diverse people, companies, and resources to develop LNG projects. As such, it is necessary to discuss both technical and commercial issues across the fences that may exist within participating organizations. This paper will continue on the path forged in 2005, discussing the latest LNG Technology issues, primarily for a commercial audience. With open discussion, both technical and commercial companies can forge ahead to develop the LNG plants of the future.

II. LNG Train Size and Size of Overall Complex

During the development of the LNG business, there has been a continuing debate about the optimum size of an LNG train [4]. Some of the issues involved are as follows:

- Overall economics improve with larger size trains
- Overall economics improve with larger size complexes
- Overall size of new complex should not be greater than immediate market demand
- Volume of natural gas reserves may limit complex size
- Market demand will increase if the economics are improved
- Facility must be as reliable as economically practical
- Using proven equipment leads to reliability
- What risk management is necessary to select the optimum size train and complex?

An important challenge in developing new LNG facilities is how to improve the overall economics while accounting for all the factors listed above. These issues lead to extensive debates between technical and commercial teams regarding risk management and project economics. In 2008, the debate continues as projects are proposed for a wide range of train and total facility capacity.

Advocates of large trains believe:

- Big is beautiful as it produces the best economics
- Large trains reduce the number of equipment items that can fail, affecting availability
- We can tie up a big market with our large capacity trains
- We can use the “two in one” concept to reduce total plant outages
Proponents of smaller trains believe:

- Small is beautiful as there are more natural gas fields that can supply my LNG train
- Smaller trains are not complicated – the development cycle is shorter
- The bigger trains are not yet proven; why take the extra risk?
- If my project is close to my market, I can overcome the economic advantage of competing larger trains
- Economics for larger trains suffer from issues of construction complexity and a limited vendor base for large equipment
- We can target smaller markets or be a part of larger market and do well

Moreover, let us not forget about the “middle grounders” – those that will build what has been built over the last decade with the following beliefs:

- Mid-size train sizes are proven: why take the risk on large trains?
- Mid-size trains take advantage of the best economic train currently in operation
- Combine the best train size to achieve the desired complex size
- We have enough commercial risk and we do not need additional technical risk

In the previous paper, we presented a graph of train size growth over time. Figure 1 is an updated graph including the most recent projected trains based on published data. As you can see from the figure, the upcoming projects are mixed in that some projects are going to smaller trains, some to larger trains, and others stay in the middle of the road. Because of this diversity, who is right?

![Figure 1: Diversity of Train Capacity for New LNG Projects](image.png)

The answer may be part of an old expression: “you are unique, just like everyone else.” It would seem that this dictum is true for LNG projects; the companies involved make each project unique to fit the specific circumstances that each project must face. As a result, there does not appear to be any universal solution to the debate over a correct train size.

Even though there are three philosophies on preferential LNG train size, there are technical issues that drive the decision of setting an actual train capacity. The remainder of this section includes additional technical details about these issues for the more “technically minded”. Discussion of LNG plant costs begins in Section III.
II.a. Technical Discussion of LNG Train Size

In an LNG liquefaction plant, mechanical power is converted into refrigeration to liquefy natural gas. In theory, as more power is added to the refrigeration system, more natural gas can be liquefied in an LNG train; but all mechanical systems have limits in their design and functionality. The challenge in developing LNG projects is to find the best use of power from cost effective and reliable equipment to meet the requirements of the markets served.

Liquefaction plants are designed along the train concept. An LNG train is the set of equipment, commonly aligned in series, designed to treat and liquefy natural gas. Additional trains are added to an existing plant (of identical or different capacity) as incremental investments in new LNG capacity. The trend within the LNG industry has been to push the limits of LNG production capacity of a single train. The driving force behind this trend has been the effort to improve overall project economics by taking advantage of the economies of scale seen in larger train sizes.

The available equipment that provides mechanical power to make LNG are gas turbines, steam turbines, and electric motors. Gas turbines come in fixed sizes while electric motors and steam turbines can be sized for an exact power output. Gas turbines are primarily used in LNG plants due to their high power output relative to their size and weight. In addition, using gas turbines does not require utilities to provide water and steam systems. The power output under standardized conditions for commonly used gas turbines is listed in Table 1 and a graph of LNG capacities as a function of driver selection is shown in Figure 2. The actual available power is based on the specific plant operating conditions and is different than that listed in Table 1. In addition, a metric of specific power (megawatts of power per million metric tons per annum - MW/MTPA) is introduced to loosely correlate the overall power for compression (turbine power + electric motor power) with LNG capacity. Helper motors are added to gas turbines to supply additional power for capacities between the data points in Figure 2.

<table>
<thead>
<tr>
<th>Driver Type</th>
<th>ISO Power</th>
</tr>
</thead>
<tbody>
<tr>
<td>GE Frame 5</td>
<td>32 MW</td>
</tr>
<tr>
<td>GE Frame 6</td>
<td>43 MW</td>
</tr>
<tr>
<td>GE Frame 7</td>
<td>87 MW</td>
</tr>
<tr>
<td>GE Frame 9</td>
<td>130 MW</td>
</tr>
</tbody>
</table>

Specific Power ~ 35 MW per MTPA

To calculate capacity, gas turbine power is derated 80% from ISO for a “typical” tropical location.

Table 1: Gas Turbine Data & Specific Power

As previously shown in Figure 1, the historical trend in LNG plant design has been showing accelerating growth in train size. LNG train size increased from the initial 0.4 MTPA in 1964 to 2.0 MTPA by 1980. After 1980, train capacity accelerated through 3.0 MTPA and recent trains...
have production around 5.0 MTPA. The newest developments in Qatar that are due on-stream starting in 2008 will have a single train capacity of 7.8 MTPA and other potential designs have already planned a capacity over 8.0 MTPA. Today, new “baseload” developments are trains that usually have a capacity over 3.0 MTPA; proven operating experience exists for trains up to 5.2 MTPA.

LNG train size must account for the size of the natural gas reservoir used as feed gas for liquefaction. The gas field must support the capacity of the plant for the expected life of the project including any possible local demand. Typically, LNG plants are designed for 20 years of operation. As a result, approximately 1.0 TCF of natural gas can support 0.8 MTPA of LNG for 20 years. For new natural gas finds, the drive to monetize that entire asset can set the capacity of baseload liquefaction but it must be consistent with the overall LNG market demand.

During this period of growth, capacity increases are becoming more difficult to achieve in a single train due to the size limitations of power systems, equipment, piping, and valves. In a single train, all major process streams narrow to a single flow at several points in the overall process, which causes mechanical limitations in controlling flow, compressing large volumes of gas, and physically supporting large mechanical systems. When reaching mechanical limitations, the normal reaction is to design parallel equipment, which increases the complexity of the train. Avoiding parallel equipment keeps the operation simple and avoids possible flow misdistribution when splitting into parallel process streams. However, within the definition of a single train, some designers have used parallel equipment to overcome mechanical limitations or to keep equipment sizes within proven ranges.

For capacities up to 4.5 – 5.5 MTPA, a single train is considerably less expensive than two identical 50% trains [1]. With a capacity over 4.5 – 5.5 MTPA, a single LNG train approaches a current scalability limit when not allowing parallel equipment (keeping the equipment count the same) or additional refrigeration cycles (e.g. new process technology). As equipment sizes become larger than those that are readily available, the number of equipment suppliers is limited and the cost of equipment and auxiliaries will cost more than assumed by scaling according to capacity. The physical installation of large equipment requires a greater effort in plant layout and construction, which provides unique engineering challenges that are outside standard and routine practice. For example, the cost difference in comparing a 6.0 MTPA train with two 3.0 MTPA trains could be in the order of 10% or less; this result challenges the trend to build larger single trains just to achieve economies of scale. In such evaluations, one has to account for cash flow analysis; in general, it is faster to build a smaller train than a larger one.

![Figure 3: Example of Machinery Configuration for 4.5 – 5.5 MTPA with a C3MR Process](image)

In order to consider potential increases in capacity, the base case will be defined in Figure 3 as two Frame 7 gas turbine drivers with a starter/helper motor for each string. Liquefaction is based
on a C3MR process. Because of the relationship between available power and LNG production, the limit of a dual Frame 7 configuration (without parallel equipment) is in the range of 4.5 to 5.5 MTPA. This capacity is a function of the available power, feed gas composition, LNG product specification, and ambient conditions. Plant capacity can increase from the base case by improving process efficiency, increasing equipment size, or adding equipment. New liquefaction technologies and equipment will also allow an increase in capacity; new technologies are discussed in Section VI.

Other process improvements can achieve an incremental increase in capacity from the base case. Each of the options listed in Table 2 require modifications to equipment or systems that alter the complexity of the base design. In total, these modifications can increase the capacity 10-20% from the base case. Most of these improvements have already been implemented for plants around 5.0 MTPA using a base set of machinery. In addition, ambient temperature has a significant effect on plant capacity as available power and cooling capacity are affected in warm climates. As a result, it is difficult to compare plants designed for arctic regions with those located close to the equator.

The second set of options to increase capacity pertains to the critical equipment: the refrigerant compressor capacity and available compressor driver power. Step changes from the base case to larger compressors or power systems are only permissible when manufacturers can guarantee performance for changes in throughput or operation. One example of a new driver for baseload LNG is discussed in Section VI. Even with changes to critical equipment, other vessels in the LNG plant are constrained when scaling capacity to higher limits.

<table>
<thead>
<tr>
<th>Process Efficiency Improvement</th>
<th>Result of Process Improvement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Add end-flash system</td>
<td>More LNG at same refrigeration power</td>
</tr>
<tr>
<td>Use larger electric motor</td>
<td>More power available for refrigeration</td>
</tr>
<tr>
<td>Use liquid hydraulic turbines</td>
<td>More LNG at same refrigeration power</td>
</tr>
<tr>
<td>Increase inlet feed gas pressure</td>
<td>More LNG at same refrigeration power</td>
</tr>
<tr>
<td>Inlet air chilling for gas turbines</td>
<td>More power for same machinery (most locations)</td>
</tr>
<tr>
<td>Change liquefaction process</td>
<td>Capacity based on additional cooling and equipment</td>
</tr>
</tbody>
</table>

Table 2: Process Efficiency Improvements for Incremental Capacity Increase

The items most affected by scaling beyond the base case are the acid gas absorber, natural gas driers, scrub column, and the main cryogenic heat exchanger (MCHE). Depending on the capabilities and experience of the suppliers, these vessels approach manufacturing limitations of physical size, erection weight, or process throughput. In addition to equipment, difficulties arise for manufacturing piping, valves, and systems to support equipment and piping. A summary of these constraints is presented in Table 3.

<table>
<thead>
<tr>
<th>Constrained Item</th>
<th>Issues When Scaling Size</th>
</tr>
</thead>
<tbody>
<tr>
<td>Acid Gas Absorber</td>
<td>Weight Exceeds 1000 tons - Transport and Erection</td>
</tr>
<tr>
<td>Natural Gas Driers</td>
<td>Excessive Diameter and Flow Limitation</td>
</tr>
<tr>
<td>Scrub Column</td>
<td>Shop Fabrication complexity - Awkward Size</td>
</tr>
<tr>
<td>MCHE / Cold Box</td>
<td>Diameter Limits / Parallel Equipment Issues</td>
</tr>
<tr>
<td>Valves and Piping</td>
<td>Manufacturing Limitations and Erection Challenges</td>
</tr>
</tbody>
</table>

Table 3: Constrained Equipment When Moving Beyond 5.0 MTPA

There are engineering solutions for each of the examples in Table 3, but solutions based on providing parallel equipment will add to the complexity and cost of a slightly higher capacity plant.
In addition, relatively few suppliers manufacture large equipment, which reduces the ability to obtain competitive pricing on these items. When process systems are designed in parallel, the definition of an item within a "single train" can become confusing.

Determining an LNG train capacity is first based on market supply and demand and then on proven equipment sizes. In the current range of operational experience, there appears to be a natural limit to increases in capacity when using only proven equipment and systems. Advances in manufacturing capabilities, improved rotating equipment, and newer liquefaction technologies will allow the industry to overcome these obstacles and allow further increase in train size.

The LNG trains currently in construction are embracing these new technologies to set the new operational standard for higher capacity trains to 8.0 MTPA and higher. New projects must balance the technical and commercial risks in order to push the practical limits within a single train. However, the recent cost pressures in materials and construction will make it difficult to determine if economies of scale have been achieved at higher capacities.

III. Why Are LNG Plant Costs Rising?

It appears to be well known there has been a significant increase in the cost of upstream oil and gas projects, which includes LNG facilities. According to Cambridge Energy Research Associates (CERA), capital costs have increased nearly 100% since 2000. This dramatic increase has affected new LNG developments that have yet to adjust to these new cost norms.

Many issues drive such a dramatic increase in capital cost. Some Global supply issues that have caused rising costs are as follows:

- Commodity price inflation
- Currency and financial risk
- Many coinciding projects
- Finite supplier/subcontractor capacity
- Dramatically growing demand
- Freight cost increases
- Diminished quality
- Wage rate increases
- Staff turnover / experience level
- Limited human resources to meet project demands

![Figure 4: Increase of Upstream Oil & Gas Capital Costs Over Time](image)
In planning to build an LNG facility, sound procurement strategies must address:

- Raw Material price inflation
- Dramatically growing demand
- Finite supplier capacity
- Diminished quality
- Prices of manufactured goods

As a result, early commitment of equipment and materials is now essential to meet cost and schedule expectations. Committing material early requires a balance of commercial and technical risk that must be successfully managed for the duration of the EPC contract. Additional considerations and details specific to LNG include the following discussion on materials, labor, and the cost effect of large train sizes.

III.a. Material, Equipment, and Labor

The limitations of train capacity as well as plant cost have been hotly debated for many years [4]. Since 2005, we have seen an incredible rise in the cost of LNG liquefaction projects: so why is the cost of an LNG plant rising so rapidly? While the debate continues, some specific factors contribute to the sharp rise in cost over the last three years. A common metric for the overall project economics is the capital cost per unit of capacity, or $US per ton of LNG per year ($/MTPA). As demonstrated in many publications, the cost of LNG facilities is a culmination of many site-specific factors; the paper “Not all LNG Projects are Created Equal” discussed this point in detail [2]. As a result, LNG projects should not be compared as successes or marginal based on one cost metric alone.

One reason for the significant rise in LNG plant costs has been the cost of raw materials. Material prices have always been a metric for long-term forecasting, but the unexpected increase in the price of premium steels (e.g. using nickel and chrome) has exhibited an abnormal increase with little assurance of stability [3]. While spikes in exotic alloy prices can be rationalized in the short term, the same effects were seen on the price of common steels such as rebar and scrap metal. Although a liquefaction facility comprises more than just raw materials, the increases in material cost will significantly affect the project capital cost. For example, a single train of 3.0 – 5.0 MTPA capacity can have as much as 10,000 tons of structural steel and 6,000 tons of piping.

![Historical Nickel Prices](image1)

![Historical Ferro-Chrome Prices](image2)

**Figure 5: Example of Rising Steel Costs over Time (Courtesy of www.metalprices.com)**

In conjunction with raw material costs, the supply of specialized equipment and materials will see an even greater cost increase over traditional norms. LNG projects often push the limits of large rotating equipment and corresponding plant throughput. Machinery such as centrifugal and axial compressors, large electric motors, and industrial gas turbines are made by a select few
companies. These companies are pressured not only by rising material costs, but by the demand for more LNG liquefaction capacity that may constrain their ability to support our industry (see Figure 6). In addition, the drive for larger capacity trains mandates the use of new equipment, which requires development and testing by manufacturers. Combining the cost of material with the limited access to large industrial machinery has an added impact on the price of specialized equipment. In addition to the cost increase, material deliveries are also affected, resulting in longer schedules and additional cost.

A major contributor to rising plant costs comes from construction labor. Liquefaction plants are often located in challenging areas that are far from dense population centers with an abundance of skilled workers. These remote locations require support to provide for the thousands of workers that are employed during construction. As LNG construction lasts several years, these site labor costs are as significant as the costs for performing actual construction tasks. The costs involved with the mobilization of labor in addition to the competition for resources among other industrial projects has led to rapidly increasing costs at the jobsite. In a recent project example, the constraints on skilled labor increased direct labor and subcontracts 30% from previous norms. As shown in Figure 6, the recent period of escalating project costs coincides with a period of high LNG EPC activity, which increases competition for specialized materials and skilled labor.

![LNG Project EPC Awards by Year](image)

**Figure 6: Total Projects in EPC during the Growth of LNG Capacity**

In summary, familiar cost metrics of US$/ton of LNG production have been affected by rising costs for raw material, equipment, and skilled labor. This growth has put a significant strain on the capability to deliver new solutions for the future and the supervision to assure that the technical and commercial issues of the owner parties are met.

III.b. The Cost Effect of Larger Train Sizes

Based on LNG capacity, project economics have historically improved with larger plants. This improvement occurred during a long period of stable prices for equipment and labor. This history fuels the belief that further increases in train size will improve the unit cost, following the "economy-of-scale" paradigm.

When considering recent project experience, increasing capacity from 3.0 MTPA to 5.0 MTPA reduced the LNG unit cost by roughly 22%. This decrease was achieved by keeping the same equipment count in the train and scaling the size to suit the larger capacity. However, using larger equipment can often move the process outside of the range of proven operating experience in cryogenic service. Table 4 compares the relative project costs for various options. This example is for a C3MR process but is essentially independent of the process design.
<table>
<thead>
<tr>
<th>Total Capacity (MTPA)</th>
<th>3.0</th>
<th>3.0</th>
<th>5.0</th>
<th>5.0</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of Trains</td>
<td>1</td>
<td>2</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>Capacity per Train (MTPA)</td>
<td>3.0</td>
<td>1.5</td>
<td>5.0</td>
<td>2.5</td>
</tr>
<tr>
<td>Main Drivers per Train</td>
<td>2 x Frame 7</td>
<td>3 x Frame 5</td>
<td>2 x Frame 7</td>
<td>4 x Frame 5</td>
</tr>
<tr>
<td>Additional Driver Power</td>
<td>20 MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Relative LNG Cost</td>
<td>122%</td>
<td>142%</td>
<td>100%</td>
<td>117%</td>
</tr>
</tbody>
</table>

Basis: Liquefaction is 50% of the total facility cost and capacity exponent factor = 0.6.

Table 4: Examples of Capacity, Train Size, Drivers, and Relative Cost

Under 5.0 MTPA, there is a substantial cost difference between a single train and two smaller trains. 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%.

Similar to the comparison in Table 4, total equipment count is another indicator for plant cost. One example of a single LNG train using the C3MR process has 350 equipment items: 130 items in the train, and 220 items in offsites and utilities. If the capacity is split into two equal trains, the equipment count grows to 480, or an increase of 37% for the facility. Clearly, installation, operation, and maintenance efforts will increase with an increase in equipment count.

When pushing capacity above 4.5 – 5.5 MTPA, there is a compromise available where the refrigeration compression section of the train is split into two parallel strings. The remainder of the equipment in the unit appears a single train, thus preserving some economy of scale at a new capacity. This two-in-one concept is sometimes useful in large capacity single trains to overcome compressor or driver manufacturing limits, but the overall capital cost will increase over a train with no limitations in equipment size.

When comparing the cost of one 6.0 MTPA train with two of 3.0 MTPA, the economy of scale appears to erode. The cost for the higher capacity equipment does not increase by the 0.6 exponential capacity factor as traditionally believed, but nearly doubles in cost. This effect is due to the limited number of suppliers, the addition of parallel equipment, and the manufacturer risk associated with the design to a higher capacity. In addition, larger piping and equipment requires more plot space, structural support, and a longer installation time. All of these factors may make larger trains less advantageous than two smaller trains. However, many other factors have to be evaluated to reach a conclusion as to the best train size; new projects have embraced both the large train capacities and the two-train approach.

IV. Site-Specifics

Site-specific issues not only affect the capital cost of a facility, but also provide numerous technical and environmental challenges. The jobsite is a “wild card” in project development; the known and unknown details will drive the level of technical definition, quantities of labor and material, and ultimately, the total installed cost. In an example for a 4.5 MTPA project, site-specific criteria could affect the project cost by nearly a factor of 3 [2]. Some of the areas that are most affected by site-specifics are marine facilities, labor cost, environmental issues, and the effects of meteorological data.

The extent of marine facilities, which include the jetty trestle, platform, and LNG loading system, is very site specific. In general, LNG liquefaction sites are located in remote locations with little or no infrastructure. LNG ships are large vessels with a significant hull depth beneath the waterline. In order to provide a seabed clearance for the vessel (total depth of at least 13.5m), the end of the jetty head must be located far enough offshore to allow the vessel to arrive, berth, and depart from the plant. If this depth is difficult to obtain, dredging of the seabed will be
required. Some sites may require a manufactured offshore breakwater (i.e. a long physical wave barrier) to reduce the wave intensity at the jetty platform, which allows the ships to load safely. A man-made breakwater can cost in excess of US$100 million.

Marine facilities are independent of the process configuration and plant capacity, unless a second berth is required to offload a high plant capacity. In general, one loading berth can accommodate a plant capacity of 7-8 MTPA; at higher capacities, additional berthing is required to load multiple carriers. A rule of thumb for the cost of these facilities can be expressed in terms of the jetty length (US $50,000/meter) which can span several kilometers. Although the jetty cost is dependent on the length of the trestle, the greatest expense is in the costs at the end platform and the effect of sub-sea soil conditions on the support structure.

Figure 7: How Long Is Your Jetty?

A major site-specific contributor to the project economics is the cost of labor, which is both capacity and location dependent. Labor costs can amount to nearly half the cost of plant erection depending on the quality and quantity of available labor for the project. Overall, labor costs are affected not only by the available labor pool, but also by the construction execution plan, the timely delivery of materials, and job-site training.

One way to reduce the amount of construction labor at the jobsite is to consider the modularization of plant sections or process units. Modularization is a means of engineering process systems or equipment in a transportable structure to be integrated at site. Modularization strategies are beneficial for offshore LNG and onshore LNG projects in challenging locations or areas with high labor costs, such as Northern Australia. Additional discussion of modularization is presented in Sections V and VI.

Another important site-specific issue is the effect on the environment, which mainly consists of plant emissions. Emissions come from different sources, but important environmental contributions to consider are construction impacts, management of acid gases, and performance of fired equipment. Each of these items contributes to the overall environmental impact, which might require different mitigation methods in different jurisdictions around the globe.

Large-scale construction projects require considerable industrial equipment in order to clear and level land (including dredging for marine systems), move and erect material, and build permanent infrastructure. For liquefaction projects in remote areas, these construction impacts affect grassroots facilities in various ways. Projects such as Tangguh LNG in Papua, Indonesia, are located 3,200km from Jakarta in a pristine heavily forested area. These sensitive locations require the mitigation of construction and operational impacts to air, water, and soil in order to
protect and serve the community at large. Moreover, the successful efforts to provide “sustainable development” in these areas have resulted in infrastructure that creates positive changes in neighboring areas.

Raw natural gas used as the feed for LNG plants will contain varying levels of acid gases, which include CO₂ and sulfur compounds such as H₂S and mercaptans, with CO₂ being the largest component. These acid gases must be removed from the feed prior to liquefaction. For a 5.0 MTPA plant with a high CO₂ content in the feed, the amount of CO₂ removed can be over 2 million tons per year. In some areas, authorities may require CO₂ sequestering, which results in complex re-injection into a nearby deep reservoir. The cost of such sequestering can significantly contribute to the cost of treating the feed. Projects with low acid gas concentrations have more flexibility in treatment and disposal of these components.

The operation of fired equipment, especially gas turbines used to generate electric and mechanical power, is a considerable source of emissions. For the same 5.0 MTPA LNG plant, the CO₂ emissions from fired equipment can be in the order of 1 million tons per year; this amount is equivalent to 200,000 passenger cars. This CO₂ cannot be treated like acid gas in the feed due to the complications of oxygen in the turbine exhaust. Technology developments challenge the efficiency and operability of fired equipment in order to reduce environmental impacts within the plant. Improvements such as using combined cycle power systems, mechanical improvements to engines, and sophisticated control systems can boost efficiency and lower the impacts of LNG infrastructure.

Ambient conditions, such as air and water temperature, have significant effects on plant design. Plants have been mostly located near the equator, but newer facilities are located in colder climates such as Norway and Russia. Regardless of location, as ambient conditions change over the course of a year, the LNG production is constrained by limitations of mechanical equipment. The power provided by a gas turbine is a function of the inlet air temperature and the efficiency of the refrigeration system is affected by the temperature of the cooling medium (if using air or water).

If the cooling medium temperature fluctuation is minor, e.g. areas close to the equator for an air cooled plant with gas turbine drivers, the impact on the production swing is low. In areas with a significant temperature fluctuation, the plant must be designed for either a low, high, or average air temperature. For example, if the plant is sized for a high ambient temperature, the equipment will constrain production for most of the year when more power and cooling duty is available during colder months. If the plant capacity isn't dictated by previous sales or marketing restrictions, it is a challenge to design the facility around changes in ambient conditions.

V. Offshore LNG

Similar to the discussion in Section II on LNG train and overall complex size, the size of an offshore facility is a critical issue. The issues regarding LNG train size and equipment are more or less the same for offshore LNG, so additional discussion on offshore LNG train size is not included in this paper.

Knowing the scale and complexity of baseload liquefaction projects, one might ask, why would you ever consider offshore LNG? As with most development projects, there are many factors to consider that can influence the decision of moving a project offshore. These factors are both technical and commercial in nature and the culmination of these issues can push a unique set of project circumstances to be the first viable offshore LNG project. For the sake of this discussion, this section will refer to baseload floating liquefaction facilities (commonly known as FLNG) and not liquefaction projects on fixed platforms, gravity based structures (GBS), or floating LNG receiving terminals. The hull structure for the floating liquefaction facility will be a purpose-built
barge and not a conversion or adaptation of any other existing or currently designed vessel (such as an LNG carrier or an existing or retired FPSO).

Offshore LNG is the merging of two well developed industries: the design and construction of large FPSOs (floating, production, storage, and offloading vessels) and the design of cryogenic systems, or onshore LNG. Graphically, offshore LNG combines links in the "LNG Value Chain" by merging gas conditioning, liquefaction, storage, and offloading in one vessel. Similarly, a floating LNG receiving terminal would combine LNG storage, vaporization, and transmission in one vessel. Large FPSOs are operating around the world in oil and LPG service since 1978, and baseload LNG plants have been built since the 1960s. If properly integrated, the production plant is simply the upper portion of the vessel (topsides), while the hull of the FPSO is designed for the weight of the process plant, the wind/wave characteristics of the site, and the volume of liquid storage.

![Figure 8: Traditional LNG Value Chain](image)

![Figure 9: Offshore LNG Value Chain](image)

Traditional FPSOs meet important criteria: production, storage, and offloading at the source of the asset; away from a comparable onshore facility where costs have rapidly escalated for materials and labor. In addition, as large gas reservoirs are found further offshore, the basic cost of transporting raw gas to a liquefaction plant has risen tremendously. This transportation cost is similar to traditional pipeline costs, but for untreated gas [1]. Some reservoirs are located so far offshore, that the offshore pipeline itself is near the limits of technical and commercial feasibility. These expensive offshore pipelines must be designed for transporting raw gas, such as liquids formation, wax deposition, and pipeline corrosion. FPSOs are commonly designed to treat raw natural gas, while LNG carriers commonly store cryogenic liquids; such that the "new" part of the project is the addition of the LNG liquefaction to an offshore vessel.

Safely producing LNG at the source of the asset eliminates onshore marine systems. These systems are sizeable investments depending on site-specific conditions such as the available water depth, wave criteria that drive the length of a jetty, dredging required to accommodate LNG carriers, and potential costs such as a manufactured breakwater to limit the motion between the loading vessel and the fixed jetty. Eliminating the onshore LNG storage and transfer infrastructure can also benefit a project that has unique environmental criteria that affects the development of the project. Although the FPSO will meet required environmental regulations, the offshore location of the vessel may facilitate the permitting and approvals required to achieve final investment decision (FID).
A large FPSO can be built to staggering dimensions. Such a FPSO could have a deck area of approximately 500m long by 90m wide. This vessel would be moored in place and connected to the gas reservoir by a turret to receive natural gas from below the waterline. However, a baseload FLNG project isn’t necessarily limited to one purpose built barge. Similar to adjoining offshore platforms or even integrating process units onshore, one or more barges can be connected to separate gas treating from liquefaction, storage, and offloading. In this scenario, one barge can be optimized for liquefaction, while another barge fulfills a traditional role of a gas processing vessel with proven subsea connections linking the two vessels.

Figure 10: An Example of a Large Scale FPSO in Hydrocarbon Service (Courtesy of BP)

The unique benefit of offshore LNG design is the reduction of construction and commissioning workhours at the jobsite, which is commonly in a remote or challenging location. Field workhours in any location can be costly; each workhour has the associated cost of providing for a large labor force in a non-industrialized area. Large FPSOs are built in select fabrication yards that are accustomed to building large ships and purpose-built barges. These skilled labor yards are efficient places for construction and integration that could be more costly in remote grassroots facilities. In areas where construction workhour costs are high, relocating construction and commissioning hours to efficient fabrication yards can significantly improve the project economics.

In addition to using fabrication yards to build the barge, there are other methods of planning LNG projects such that the process units within the project, or modules, can be built in parallel with the construction of the barge. A module is similar to a steel reinforced box, which contains a certain amount of process equipment and piping. A module can be as simple as a group of piping elements or as complex as an entire process unit in excess of 10,000 tonnes. By using modules, the project designs and constructs the topsides and the hull in parallel in order to optimize the overall project schedule. This integration improves upon the traditional methods of onshore site preparation that is required before constructing an LNG facility piece by piece. Offshore LNG will require innovative execution strategies in order to design, construct, integrate, deliver, and commission, a safe world-class liquefaction facility.

The design of an LNG FPSO is mostly independent of liquefaction process technology. However, using parallel equipment will increase the complexity and required plot space on the FPSO. Although each liquefaction process has its own challenges with the performance of proprietary and ancillary equipment, each technology can compete in the realm of offshore LNG. Owners will prefer technologies based on criteria such as efficiency, amount of hydrocarbon inventory, or even operator familiarity. However, each technology will be adapted for marine installation and the associated motions that exist when operating offshore. In fact, offshore LNG is a natural
example of a design that can be expanded by the addition of multiple vessels to a base installation, or a configuration that can be relocated based on a limited life of a reservoir and the ability to treat a wide range of gas compositions.

The area with the greatest promise to change the development of offshore LNG is in the area of cryogenic liquid transfer systems. Conventional onshore LNG transfer systems (LNG loading arms) have been adapted for offshore sea states, but the next generation of LNG transfer systems could be cryogenic hoses that accommodate greater motion between two vessels and provide assured methods of LNG transfer during significant wave heights. In addition, these flexible loading systems will maintain the insulation properties required for thermal efficiency and the LNG transfer rate required to load an LNG carrier in a suitable time. Cryogenic transfer is one of many technologies that will adapt to the lucrative market of large baseload FLNG production facilities.

The development of baseload offshore LNG is within sight, but the exact configuration of this project is still under debate. The first FLNG project may move forward based on break-even economics with a comparable onshore plant or wield the greatest advantage of economy of scale within the fabrication limits of the best modularization yards. There is little doubt that innovative project development and contracting strategies are necessary to bring FLNG to fruition. All of these challenges have been conquered in the development of large oil and gas FPSOs and large scale onshore LNG projects of the 21st century; successful integration is the key driver for FLNG.

VI. Recent Technology Innovations

As new LNG projects are developed, there are opportunities to integrate newer technologies to the world of LNG. One long held concept is to identify equipment or ideas that have less than two years proven experience in similar services or process conditions. If the concept or equipment does not meet the two year benchmark criteria, then it may still be acceptable if the appropriate risk management concepts are applied. This philosophy is how the LNG business has evolved during its entire history of technical development. Innovations commonly involve the large industrial equipment needed to handle the flows for increasingly larger train capacities. In addition to improvements in equipment, newer process technologies have been implemented for larger baseload facilities and niche markets of modest throughput. Some of the most significant developments over the last few years include the use of new mechanical drivers for the refrigeration compressor system, new process licensor technologies for baseload LNG, and the first uses of LNG modularization.

VI.a. GE Frame 9 Industrial Gas Turbines

The examples in Section II and III have used GE Frame 7 industrial gas turbine drivers; Frame 7 gas turbines are the largest machines of proven experience used to make LNG trains of 5.0 MTPA. To increase capacity of a single train, larger machinery is necessary to provide the additional power required to liquefy more gas. Frame 9 gas turbines have been a workhorse in the electric power industry since the 1970s; however, the machine had never been used in mechanical drive for LNG refrigeration. The Frame 9 has a distinct step up in power: 130 MW at ISO conditions, a step change of nearly 50% more power than a single Frame 7.

The six LNG trains in construction in Qatar (see Table 5) are using three Frame 9 gas turbines for each LNG train. These machines support the use of the new APCI AP-X® liquefaction process technology that allows the design of a single train to 7.8 MTPA. The change to using the Frame 9 is not solely to provide more power to increase capacity, but is also related to the speed of the machine. The Frame 9 operates at a lower speed (3000 rpm vs. 3600 rpm) which allows a higher throughput in the compressors before reaching design limitation.
The Frame 9 was successfully tested for use in Qatar and the first train to begin operation is scheduled for 2008. Other projects in development have viewed the Frame 9 as technically sound and are incorporating the machine in plans for new trains. However, projects must evaluate the risks of using this technology until the train performance results are evaluated. In the coming years, the path toward designing higher capacity trains will be based on the performance of these six trains.

VI.b. Large Electric Motor Drives

Similar to the use of Frame 9 gas turbines, large electric motors have now become a viable alternative for driving critical refrigeration compressor systems. Electric motors have the benefit of being sized to an actual refrigeration power demand and are not restricted by a limited selection of sizes. In addition, large motors claim to have 99% availability and 98% efficiency in transmitting electrical power to the compressor system. However, large motors have technical challenges such as the design for variable speed drives (in order to start the motor and regulate speed) and the harmonics inherent in their design.

Even though the electric motor appears to replace a gas turbine, electric power is still required to drive the motor. In effect, the required electric power is relocated to the electric power generation plant required to support the rest of the facility. In this scenario, the power generation plant will absorb the extra power load using additional proven machinery commonly found in large independent power plants. A power plant can be designed in ways to improve efficiency or emissions as required by the project economics or local requirements. One of the advantages of this scheme is that the erection of major drivers is more spread out and not concentrated within the process train, which may be helpful in reducing schedule.

The Snøhvit LNG plant uses Siemens 65 MW electric motors as refrigeration compressor drivers. These motors are the largest ever used for a liquefaction project. Electric motors are well suited for a modular design, such as the barge-mounted liquefaction train for Snøhvit LNG (see Section VI.e). Companies claim the capability to design electric motors of 100 MW or more for service in baseload LNG. The Snøhvit LNG plant was commissioned in 2007 and will be closely watched as to the success of this electric motor drive scheme.

VI.c. New Liquefaction Process Technology

In the first decade of baseload LNG, five different liquefaction processes were installed in the first five grassroots plants. Thereafter, the APCI propane pre-cooled mixed refrigerant (C3MR) process dominated the world of LNG for 24 of the next 26 EPC projects. Over the years, the C3MR technology gradually pushed train capacity to 5.0 MTPA (SEGAS LNG). In 1999, a 3.0 MTPA plant based on the revived Phillips (now ConocoPhillips) Cascade process was completed in Trinidad; since then, advancements in cascade technology have led to a train capacity of 5.2 MTPA utilizing the two-in-one train concept.

As a result of the renewed competition among process licensors, several companies are now in different stages of developing and marketing new or modified liquefaction process technology. Although there are many technologies available, the latest projects utilizing new technology are listed in Table 5. Other LNG projects in construction continue to use successful proven technologies such as APCI C3MR, ConocoPhillips Cascade, and SGSI C3MR.
<table>
<thead>
<tr>
<th>Project</th>
<th>Technology</th>
<th>Trains</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Snøhvit LNG</td>
<td>Linde MFC™</td>
<td>1</td>
<td>4.3 MTPA</td>
</tr>
<tr>
<td>Sakhalin LNG</td>
<td>SGSI DMR</td>
<td>2</td>
<td>4.8 MTPA</td>
</tr>
<tr>
<td>RasGas III</td>
<td>APCI AP-X™</td>
<td>2</td>
<td>7.8 MTPA</td>
</tr>
<tr>
<td>Qatargas II, III, &amp; IV</td>
<td>APCI AP-X™</td>
<td>4</td>
<td>7.8 MTPA</td>
</tr>
</tbody>
</table>

Capacity listed is for each LNG train
Snøhvit LNG commissioned in 2007, all other projects in EPC

Table 5: New Process Technologies Used for Baseload LNG Plants

Of note in Table 5 is the commercialization of the APCI AP-X™ process, which has pushed the limit of single train capacity to 7.8 MTPA. This new process is an extension of their successful C3MR technology by adding a nitrogen refrigeration loop to provide additional cooling capacity. By reducing the refrigeration load on the traditional propane and MR cooling cycles, this technology allows for greater capacity in a single train without having parallel critical equipment [8]. Although this technology does add equipment via the new refrigeration cycle, the future shall reveal if the overall economics and construction schedule has improved for a step change in capacity beyond 5.0 MTPA. Depending on site-specific issues and future modifications, train sizes based on AP-X™ can be built for capacities beyond 8.0 MTPA.

VI.d. Aeroderivative Gas Turbines

Darwin LNG was the first baseload LNG plant to implement GE LM2500 aeroderivative gas turbines as refrigeration compressor drivers. An aeroderivative gas turbine is adapted from an aircraft engine and has the benefit of being lighter in weight and more thermally efficient than an industrial gas turbine, but a more expensive machine per MW of power produced. Aeroderivative turbines can fit special circumstances, but are currently not available in large power ranges such as the larger gas turbines listed in Table 1.

The actual turbine model used, a GE PGT25+, is similar in power to a GE Frame 5D industrial gas turbine (~32 MW), but with a 12% higher thermal efficiency at standard conditions [9]. Due to the thermal performance, an aeroderivative turbine can improve life-cycle economics when the cost of fuel gas is high and the machine is successfully matched with liquefaction process technology and characteristics of the jobsite. However, the overall economics must account for the higher fuel gas pressure required for aeroderivative turbines compared to conventional industrial machines. The 3.4 MTPA Darwin LNG plant began operation in 2006.

VI.e. Modularization Experience

As discussed in Section V, modularization is a concept to design, build, and commission systems of equipment and piping in self-supporting transportable structures. Modules are built in large scale fabrication yards in order to relocate expensive site construction hours to efficient industrial locations. Modular engineering is used in FPSO design in order to design the hull and process trains in parallel. Although there has yet to be an LNG facility fully optimized for modular design, there are two recent examples where modularization concepts are applied.

The liquefaction portion of the Snøhvit LNG project in Hammerfest, Norway was designed and constructed on a custom-built barge. Fabricated in Spain, the barge was towed to Norway and permanently fixed to the site. This strategy of pre-fabricating process units in an industrial location reduced the amount of construction hours that would have been required in an arctic location.
The Woodside Train V Expansion Project in Karratha, Australia took a different approach to modularization. This project modularized an existing design for Train IV in order to achieve the benefits of relocating field construction hours while adhering to the same plant layout from an operating train. This design will use more structural steel than the existing train IV project but may have yielded benefits in either project schedule or overall capital cost. The 4.2 MTPA train is due to begin operation in 2008.

Many developments are still looking at modular designs for new facilities – for both onshore and offshore locations. The primary issues that need to be addressed include:

- Schedule impact
- Cost impact
- Local content issues
- Safety issues related to equipment separation distances

Although there are many benefits to modular construction, the support steel of the module makes the design more compact and will make future renovation of the facility more difficult than for a traditional design.

VII. Summary

The purpose of this paper is to foster the alignment among technical and commercial professionals who all have an interest in the growth of the LNG market. As every new development will forge its own path, each project will take on a set of technical and commercial challenges that make their project unique. Today, some of technical challenges involve the sizing of LNG trains, the cost of LNG facilities, site-specific criteria, the prospect of offshore LNG, and the newest technical innovations.

The next few years will showcase experience with LNG plants built in new locations, with larger train capacities, and using new equipment and technologies. As the industry evaluates these newest developments, both technical and commercial specialists will jointly develop the LNG strategies for the liquefaction plants of the future.
VIII. References


3. Data for raw material costs provided by: www.metalprices.com


