Current Myths About LNG

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KBR
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ABSTRACT

Since the startup of the first baseload LNG plant (Camel) in 1964, there have been several generations of LNG plant designs. Each generation can be defined by a noticeable step change in elements of the overall plant configuration. These steps may include developments in equipment, changes in cooling media, breakthroughs in train throughput, or combinations of changes leading to new industry standards or benchmarks. Since the first LNG projects with train capacities of less than 1 Mt/a, generations of technical innovations have led to operating trains of nearly 8 Mt/a, and front end engineering designs (FEED) exceeding this current benchmark.

Regardless of the state of the LNG industry, there are often misconceptions regarding the application of new technologies, determination of process configurations, or implementation of project execution strategies to reduce project costs and shorten schedules. These misconceptions or innocent mistakes, if perpetuated at conferences or reflected in FEED, can be perceived as reality. These “design and execution myths” will result in less accurate cost estimates or increased technical and execution risk for new projects.

This paper will review LNG technology and project execution myths that could derail the innovation necessary to develop the next generation of LNG projects. By openly discussing these myths, we can stimulate constructive debate on the challenges facing today’s projects.
**Introduction**

The growth of the LNG industry has been based on consistent advancements in project execution and technology innovation. Improvements in the design and construction of LNG plants have led the way to larger liquefaction trains, optimization of plant cost, and the best use of material and human resources. To support future opportunities, each new idea or innovation requires the evaluation of the expected benefits of change against the technical and execution risks that can affect a project or the industry as a whole.

Many communities and industries have benefited from the growth in LNG. As a result, new projects (both liquefaction and regasification) are being considered for dozens of new onshore and offshore locations. In recent years, higher project activity has allowed more companies (stakeholders, designers, manufacturers, etc.) to participate in the design, construction, and operation of these facilities. As a result of the expansion of the “LNG community”, there is a need to share lessons learned from past projects to promote the best practices that will lead to continued growth. Without the insight from these lessons, new entrants to the LNG industry may unknowingly increase the technical and commercial risk on future projects.

The purpose of this paper is to introduce and discuss current myths about LNG that will affect current and future projects. These myths are often the result of ideas that have not been fully implemented on operating projects or conclusions that are not supported by project experience or technical analysis. This paper is not intended as a means to display exact cost and schedule metrics to defend each position. Future development teams must prove to their clients that their services, products, and concepts are technically and economically viable. This discussion is intended to provide insight from the contractor perspective and promote an open debate about how to best solve technical and execution challenges.

**Current Myths About LNG**

Technical conferences and publications are ideal forums to discuss issues facing owners, manufacturers, contractors, and communities in the LNG industry. However, the most challenging technical and commercial issues affect actual projects in the development cycle; these projects, protected by strict confidentiality, cannot be discussed in these forums. Occasionally, companies may share lessons learned from completed projects to a wide audience; but those lessons may come years after project completion, if at all. Due to the lack of project-specific context, some ideas may develop into misconceptions or myths. These technical and commercial myths may lead to optimistic assumptions about project costs, implementation schedules, equipment configurations, reliability and availability, etc.

A myth is defined as a false notion or story concerning a person or event, with or without a determinable basis of fact or explanation. Myths can be perpetuated by the potential for great reward without full consideration of risk, data, and experience. Perpetuating a myth is often done unknowingly when there isn’t enough experience or publically available data to believe otherwise. For a business or industry, as opposed to a person or event, the number of myths is inversely proportional to the maturity of the business. This maturity is directly proportional to the amount of information that is publicly available about the subject matter. For example, there are fewer myths about the oil industry than the LNG industry due to relative maturity of technologies and the total amount of project experience. Confidentiality, intellectual property, and trade secrets can help perpetuate myths due to the protection of insightful data or experience. As a result, myths can only be exposed by the sharing of experience to support a logical conclusion.
Current myths about LNG are often innocent mistakes based on false assumptions, incompatible experience, aggressive marketing, or misunderstood facts. These myths may be stated as facts to suit the promoter, author, or proponent for a product, service, or idea for development. Myths about LNG often cover absolute statements that are difficult to refute without significant analysis (e.g. most efficient, shortest schedule, lowest cost, highest availability, etc.). False assumptions or aggressive marketing may have consequences when developing new projects as experience has shown that not all LNG plants are considered equal [1]. With an open debate and a greater insight to LNG lessons, facts, data, and trends, myths about LNG will be openly discussed and eventually disproven.

**Myth: Modular construction saves cost and schedule**

With the growth in the potential number of new onshore LNG projects, modular construction is often regarded as a way of reducing capital cost and EPC schedules. This benefit would be derived from shifting a significant portion of construction labor from the plant site to a module fabrication yard. The positive features of modular construction include higher labor productivity, mitigation of weather-related delays, and lower wage costs when compared to remote or expensive locations. Schedule risk can be mitigated by shifting construction work to a controlled manufacturing environment. For traditional construction, weather uncertainties combined with the logistics issues for remote sites can greatly affect the construction schedule.

While the benefits of modular construction may prove to be positive overall, few operating LNG projects have chosen a modular solution. Operating LNG projects that have used a modular execution strategy are listed in Table 1.

<table>
<thead>
<tr>
<th>Project</th>
<th>Location</th>
<th>Reason for MC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sakhalin LNG</td>
<td>Sakhalin Island, Russia</td>
<td>Weather / Season</td>
</tr>
<tr>
<td>North West Shelf</td>
<td>Karratha, Australia</td>
<td>Limited and expensive site labor</td>
</tr>
<tr>
<td>Train 5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pluto Train 1</td>
<td>Karratha, Australia</td>
<td>Copy of NWS Train 5</td>
</tr>
<tr>
<td>Gorgon LNG</td>
<td>Barrow Island, Australia</td>
<td>Limited and expensive site labor + lack of laydown and accommodation area</td>
</tr>
<tr>
<td>Snøhvit LNG</td>
<td>Hammerfest, Norway</td>
<td>Weather / Season</td>
</tr>
</tbody>
</table>

Table 1. Operating Onshore LNG Projects Using Modular Construction (MC)

There are two main categories from Table 1: projects with seasonal or weather concerns and projects with limited area and/or expensive site labor. Seasonal concerns often refer to limited suitable periods for stick built construction, where site activities would be subject to long periods of inactivity caused by cold temperatures or other related factors (such as excessive mud and ice). Projects in arctic locations often fall into this category. In short, modular projects have unique site specific conditions that demand a modular over a stick build execution approach.

Another reason to consider modular execution is for a location with a lack of skilled construction labor. This situation arises where the domestic labor force is not able to fully satisfy the overall construction demand. This scenario applies for a single remote project as well as for an area with multiple developments that are competing for resources. Furthermore, regional governments may limit the importation of foreign labor to solve short term demands. In some areas, even an organized and unionized workforce is not sufficient to meet periods of high demand. As a corollary to labor issues, remote locations will have insufficient temporary accommodations; providing this
infrastructure adds significant costs to projects without adding any additional LNG production. The benefits of modular execution result in reduced site construction workhours; a modular approach could shift 50 to 66 percent of the site workhours from a remote to industrial location.

One reason why modular projects are not more common is that modular construction may have disadvantages that tend to increase capital cost. One potential disadvantage is that the modules must be designed for transportation loads (during shipping and installation), which is equivalent to unnecessarily designing for a strong seismic zone. Typically, about 60% of a module’s weight is structural steel, compared to 25% for a stick built onshore system of similar scope. While it is true that some of the transportation steel is removed after the module is set in place, the engineering, procurement, and fabrication costs of structural steel are well above the cost of a conventional stick built facility.

An important design issue for modular execution concerns the amount of engineering required during the definition phases of the project. To develop accurate cost estimates (e.g. during FEED), firm quotations are required from module yards; these quotes are often based on unit rates and quantities. The design contractor must estimate these quantities accurately, which requires completing a significant amount of “detailed design” in the FEED phase. This structural engineering would be considered excessive to support a similar cost estimate for a stick built facility. Practically speaking, this means the owner of a modular project must pay for more engineering before making a final investment decision. This modular engineering philosophy will also apply to developing a floating LNG (FLNG) execution plan for FEED.

Furthermore, this engineering and execution methodology is brutally unforgiving to post-FEED design changes. Once the module design is underway, there is understandably a strong resistance to change the process design and lose a large amount of modular engineering progress. Nonetheless, design evolution is inevitable over the project lifecycle. Compared to stick built construction, the total engineering hours increase by the extra hours to design modules as well as the time spent trying to minimize the impact of design changes. Mitigating design changes results in finding a way to “cut the foot to fit the shoe”.

For optimal execution, the FEED team must attempt to achieve “perfect engineering”: developing a process configuration and layout which can withstand the detail design phase and technical changes from downstream engineering groups. However, “perfect engineering” is almost impossible to achieve. A sound execution strategy is to develop a fully robust FEED (in many cases to the point of selecting vendors and their actual equipment) before fully committing with module fabricators. Conservatively, modular project FEED engineering hours can be at least 50 to 60 percent greater than the workhours for a stick built plant.

Modular execution is not simply a change in FEED philosophy and engineering; modular execution significantly affects procurement, logistics, and execution planning. For example, every piece of material must be at the module fabrication yard before the fabrication of a specific module may begin. The material must be available in order to benefit from the efficient fabrication methods of these specialized yards. If the bill of material is incomplete, the fabricator may choose to not begin work on your project in lieu of working for another customer under better circumstances. Stick built plants can be erected “one piece at a time” and do not require all material to be in place before construction begins.

In summary, the extra scope required for modular construction increases overall engineering workhours, and may increase construction hours depending on the relative productivities of site and module shop labor. Added materials and transportation costs
for modular construction can add to the overall cost. All of these factors should be evaluated when comparing modular versus stick built construction. In some circumstances, such as for extreme site weather or labor supply challenges, modular construction may be the only viable solution. Modular projects are not “right” or “wrong”; modular construction is chosen when the project evaluation criteria point to modular execution as the preferred path forward.

Myth: Modular construction saves cost and schedule

Truth: Modular construction is a preferred execution strategy for specific circumstances

MYTH: Floating LNG (Liquefaction) is cheaper and faster than onshore LNG

One popular LNG myth to challenge is that FLNG (a floating liquefaction plant) is cheaper to construct and is faster to execute than an onshore LNG plant. This myth is perpetuated on the notion that efficient shipyard fabrication methods and high onshore construction costs tilt the economic and project execution metrics toward preferring FLNG over an onshore plant with little consideration of capacity or plant configuration. As onshore LNG capital costs have continued to increase over time (primarily due to infrastructure costs), this myth is heavily marketed by some companies for opportunities to monetize offshore or stranded natural gas assets.

Technical and commercial issues for onshore plants and FLNG have been debated at many conferences and technical forums; some of these issues include [2, 3, 4]:

- The metric of US$ per annual ton (US$/t) of LNG production is not an accurate means to compare LNG projects,
- Few companies have the insight to the cost and execution of floating production storage and offloading vessels (FPSOs) as well as onshore LNG projects,
- FLNG requires all of the gas processing, liquefaction, and utility equipment as an onshore plant, and
- FLNG project execution follows the business model for FPSOs, with great emphasis on modularization and coordination with suppliers and shipyards.

With this background information, two issues to consider in debating this myth are the overemphasis on unit costs and the assumptions made in estimating the project execution schedule.

An additional myth of FLNG “unit cost”

When evaluating FLNG against an onshore plant, each option must be evaluated on a similar basis (i.e. required facility size for the expected design life). In addition, the respective cost and schedule estimates must have high confidence. To estimate the cost of onshore plants, the issues regarding the rise in capital costs as well as current material, equipment, and labor trends must be fully understood. On the other hand, since there isn’t an audited history of FLNG installed costs, only historical FPSO costs can be used to augment study work developing potential FLNG configurations. As a result, only with a confident understanding of both project cost and execution models can one decide the optimal project basis (onshore vs. offshore) for a new LNG facility and a specific hydrocarbon asset.

Statements perpetuating this FLNG myth use the comparative metric of “unit cost” or “specific cost” based on total LNG production per year, often abbreviated as US$/t of LNG. This simplified cost metric does not provide insight to the technical configuration of the facility or the site specific characteristics affecting the total installed cost. Based on this metric alone, unit costs for an onshore LNG project range from historical lows of $200/t to maximums approaching $2,000/t. Without site-specific and economic-specific
context, it is impossible to determine the difference between two plants based solely on unit cost.

Marketers of FLNG configurations advertise unit cost well below that for onshore projects. FLNG costs are often estimated in the range of 500 to 700 US$/t compared to onshore projects quoted at over 1,000 US$/t with high cost variability. Using unit cost, a small scale FLNG configuration (e.g. 2 Mt/a for a benign offshore location) may be unreasonably compared to a large onshore facility (e.g. a three train grassroots plant of over 12 Mt/a). To be fair, there are few current onshore projects that are proposed at small capacities to exactly match FLNG, but small scale onshore plants have lower unit costs than advertised in an onshore vs. offshore comparison. In sum, if there is such a clear cost advantage for FLNG over onshore developments, why aren’t all new projects built offshore?

In breaking down unit costs, significant elements of the project scope include issues such as overall facility size and scale, technical complexity (to achieve the nameplate capacity), and project location. Regardless of the variance of each element, the total facility cost must meet a required rate of return for the project’s stakeholders. When comparing onshore LNG versus FLNG, using US$/t will compare estimated FLNG plant costs to known onshore developments; to perpetuate the myth, FLNG estimates are compared to onshore plants of a far greater capacity and technical complexity. For equal capacities, onshore cost estimates will have higher credibility than first-of-a-kind FLNG estimates due to actual project data and experience. In addition, FLNG cost estimates may be based on an advantageous configuration that minimizes technical complexity, avoids issues with manufacturing or size limitations, and defers challenges due to the project location or gas composition. These configurations may reduce the estimated FLNG unit cost, but may only fit the development of small stranded gas reserves.

For example, FLNG configurations are currently marketed in the small to mid-scale capacity range: often less than 2 Mt/a, with a few examples at 2.5 Mt/a and above. Conversely, new onshore projects are often proposed as multi-train grassroots projects which have total facility sizes in the range of 6 – 15 Mt/a. In evaluating FLNG as an option against an onshore facility, one would have to look at a single FLNG vessel versus a small scale onshore modular plant or multiple FLNG vessels (e.g. 3 to 8 FLNG’s) operating in parallel on the same reservoir. Analyzing the unit cost of a single small to mid-scale FLNG vs. a large multi-train onshore LNG complex is not a suitable comparison. This disparity in facility size is also present when comparing project schedules.

**FLNG Project Execution – from Beginning to End?**

As discussed in recent publications, FLNG project execution is likely to follow the project execution model for complex oil and gas FPSOs rather than conventional onshore LNG plants [3]. This execution model is based on decades of FPSO design/build experience as well as the need for modularization of LNG equipment and utilities, coordination of equipment and material suppliers, interface with the shipyard (and potentially separate module and/or integration yard), and accounting for the safety of the vessel crew in design. Even if FLNG were cheaper than a comparable onshore plant, is it always faster to build and install an LNG FPSO than an onshore LNG plant?

When considering FLNG project development options, there appears to be two sets of offerings: choosing an existing “generic” or “optimized” FLNG design versus building a unique configuration from scratch. Each offering sounds attractive: the optimized design may require little to no adaptation after purchase while the unique configuration will be customized to the owner’s exact needs and specifications. Comparing each configuration involves a review of how each option would be executed for the specific conditions of a particular project, location, and gas composition.
Generic or optimized FLNG designs suggest a schedule ranging from 36 to 48 months; however, it is difficult to determine what activities define the boundaries of this duration. A generic FLNG schedule may only cover EPC (i.e. exclude FEED), which would omit any site-specific studies required to adapt a generic design to a specific location. These FEED activities are necessary to optimize the technical configuration, adapt to the metocean conditions, and improve the accuracy of the cost estimate. The generic FLNG schedule may include fabrication of the vessel, but omit site-specific activities; these activities cover towing, commissioning, subsea hook-up, and startup services. For the generic FLNG design, it is difficult to assume potential changes to the base configuration, so this variability is not included in the estimated schedule (or unit cost). As a result, generic FLNG schedules offer insight to the fabrication duration; if there are significant changes to the generic configuration, these base schedules will not include all the activities from contract award to 1st LNG.

Building an FLNG configuration from scratch follows the development cycle of large FPSO projects. The philosophy behind building customized FLNG configurations (for mid to large scale capacity) has been discussed in recent publications [3]. When reviewing the execution lessons learned from large FPSOs projects (that separate oil, water, and natural gas), we have learned that FPSOs are not generic. If the relatively mature FPSO industry is not offering cheap and fast generic FPSO designs, how can this idea work for an LNG plant?

The customized FLNG project will follow a stage gate development cycle used for most large capital projects. This execution plan will allow rapid development of alternatives for the topside configuration and hull size while generating cost estimates (commensurate with the definition) to evaluate options and the overall project viability. Farther down the development cycle, additional engineering definition (pre-FEED and FEED) will improve estimating accuracy while providing a basis to solicit competition by multiple EPC bidders. Customized FLNG project schedules will appear longer than for generic FLNG units, but will allow for greater design flexibility and cover the entire project from initial concept to 1st LNG.

An onshore LNG plant is not a generic design. An onshore LNG plant is rapidly customized to the site-specific conditions using known technologies and proven equipment. In optimizing an onshore design, each facility must account for actual ambient conditions, reservoir composition, site (e.g. soil) conditions, marine conditions,
etc. In reviewing the second part of the myth, FLNG is faster to implement than onshore LNG, we must compare equivalent development scenarios:

- A single FLNG unit versus a single LNG facility of similar capacity
- A large onshore LNG complex versus multiple FLNG units operating in parallel

A single generic FLNG unit, if suitable for use without extensive modification, may be equivalent or faster to implement than an equally sized onshore LNG facility. The myth compares a potential FLNG opportunity to an actual large LNG project; however, the schedule for an equivalent small scale onshore LNG project is not considered. A small scale onshore LNG facility can be executed in many ways in order to optimize the schedule; these options include LNG trains that are similar to those proposed for small scale FLNG. As a result, the schedule for a small scale onshore LNG facility will be a function of the LNG storage and marine facilities which can be built faster than for large multi-train projects.

Although it appears that the unit cost of some large onshore LNG facilities is higher than small scale generic FLNG, onshore facilities can be built with high schedule certainty. Since only a limited number of suppliers can build an FLNG vessel, it is difficult to build more than one FLNG unit at a time. Therefore, it is doubtful that a fleet of (3 to 8) duplicate FLNG units can be built, commissioned, installed, and integrated faster than one large onshore plant. In addition, a fleet of FLNG units requires shipping logistics for each unit; this scenario is similar to a large onshore plant that would have several jetties serving only mid-size LNG carriers. With regard to schedule, the myth may have some validity when comparing a single generic FLNG unit to a small scale onshore plant in a challenging location where infrastructure and site improvement activities lengthen project schedules.

**Summary – Comparing FLNG vs. Onshore LNG**

FLNG proponents include international oil companies, EPC contractors, entrepreneurs, technology providers, shipbuilders, and equipment suppliers. Of the proponents, many are experienced in the design and operation of FPSOs, but few combine the experience and know-how from both the FPSO and LNG industries. Proponents who are still learning the lessons of one of the two industries are still discovering that “you don’t know what you don’t know” [3].

The myth that FLNG is cheaper and faster than onshore LNG tries to isolate cost and schedule from an actual project with important site specific criteria. For small gas reserves, comparisons should be made to small-scale (modular) onshore plants, while large reserves must evaluate a large onshore complex versus large scale customized FLNG or multiple generic units. Using unit costs or generic schedules to compare FLNG versus an onshore project diverts the emphasis from developing a complete solution to selling a specific product or widget. When several FLNG facilities become operational, the industry will respond based on proven experience and shared insight to actual capital and operating costs.

Every LNG opportunity must be evaluated on its own merits as it is difficult to compare one project versus another. The technical and physical configuration of an LNG project is the result of a lengthy evaluation of the reservoir volume and composition, the potential customers and markets, the desired product slate, and the design life of the facility. Project solutions are not fulfilled by “standard” or “generic” projects, but by rapidly customized facilities (onshore OR offshore) to provide the best rate of return over the desired lifetime.

*Myth: Floating LNG is cheaper and faster than onshore LNG*

*Truth: Floating LNG, when evaluated equally versus onshore LNG, can and will be the preferred solution for certain combinations of project evaluation criteria*
Myth: Lean feed gas is best as it results in simple LNG plants

Although no two liquefaction plants are configured in the same way, each plant must be designed for a specific feed gas composition (or range of compositions) to prepare the gas for liquefaction while meeting the product specification. As discussed in many publications, raw gas is treated to remove acid gas components (CO\textsubscript{2}, H\textsubscript{2}S, etc.), water, mercury, and heavy hydrocarbons. In addition to refrigeration and liquefaction, a worst case feed gas composition will dictate the equipment necessary for the balance of the facility. Since all feed gas compositions are different, is there a preferred feed gas composition that is best suited for liquefaction? These questions lead some to believe an additional LNG myth that lean feed gas is best (as opposed to rich gas) as it results in simple LNG plants.

Although there isn’t a standard LNG composition as a result of gas liquefaction, LNG is often produced to a specification that can be accepted by a wide range of customers. While feed gas components are commonly found within an expected range, there are examples of natural gas reservoirs with extreme amounts of certain components. For example, some reservoirs may have very high concentrations of methane (e.g. shale gas or coal seam gas), heavy hydrocarbons or wax (e.g. associated gas), or even acid gas (e.g. CO\textsubscript{2} over 20%). Although there are an infinite number of feed gas compositions, a simplified example between a lean and rich gas composition is shown in Table 2.

<table>
<thead>
<tr>
<th>Component</th>
<th>Lean Gas Composition Mol %</th>
<th>Rich Gas Composition Mol %</th>
</tr>
</thead>
<tbody>
<tr>
<td>N\textsubscript{2}</td>
<td>0.50</td>
<td>0.75</td>
</tr>
<tr>
<td>C\textsubscript{1}</td>
<td>97.00</td>
<td>84.00</td>
</tr>
<tr>
<td>C\textsubscript{2}</td>
<td>1.00</td>
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<td>C\textsubscript{3}</td>
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<tr>
<td>C\textsubscript{4}</td>
<td>0.00</td>
<td>2.00</td>
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<tr>
<td>C\textsubscript{5}</td>
<td>0.00</td>
<td>1.25</td>
</tr>
<tr>
<td>C\textsubscript{6+}</td>
<td>1.50</td>
<td>3.50</td>
</tr>
<tr>
<td>TOTAL</td>
<td>100.00</td>
<td>100.00</td>
</tr>
</tbody>
</table>

Table 2. Lean Feed Gas vs. Rich Feed Gas: Is Simpler Always Better?

Regardless of the composition, the natural gas from a reservoir, associated or unassociated, needs to be prepared for liquefaction. As mentioned in many references, this preparation entails removing the components that are either undesired or would freeze out, resulting in plugging of equipment or mechanical components. Unless this processing is physically located at an upstream location (e.g. far from the LNG plant), it cannot be avoided. Nitrogen, which has a lower boiling point than LNG, must be removed after the liquefaction process if the nitrogen concentration in the LNG is above 1%. Since this myth compares plant simplicity for a lean gas versus a rich gas and nitrogen is removed after the liquefaction step, the nitrogen content will be excluded from this discussion.

On the whole, the overall complexity of an LNG plant does not change very much from one plant to another unless there is a gas reservoir that contains pristine raw material. Pristine raw material is considered to be natural gas that does not require any processing in order to be suitable for liquefaction. Pristine raw material has never been found; therefore, all LNG plants require gas processing prior to liquefaction.

Nearly all feed gas streams from any reservoir contain heavy hydrocarbons that would freeze out when cooling the gas to minus 160 C. The solubility limits of each component
in LNG are low and these limits vary from trace elements to less than hundreds of parts per million (ppm). The most prevalent heavy hydrocarbons in feed gas are hexane and heavier (C6+) as well as and BTX (benzene, toluene, and xylene).

If none of these components are present, because they have been removed in an upstream NGL recovery plant (or you are the first to discover pristine feed gas), then the liquefaction process (and resulting plant) becomes simple as there is no equipment and piping required for NGL recovery. However, the overall plant operation is complicated by requiring the importation and storage of refrigerants, namely ethylene and propane, which would have been produced by the NGL recovery unit. Upon a loss of refrigerant inventory (e.g. during unplanned shutdown requiring flaring of refrigerant), the plant could only replace refrigerant from storage as it is not a designated product of gas processing. This complication includes considerations for ordering, transportation, unloading, storage, and purification of multiple refrigerants.

A feed gas that is slightly heavier than the pristine feed, but still considered lean feed gas, may contain enough ethane and propane for suitable refrigerant makeup. This plant would appear more “complicated” than that required for pristine feed gas, but allows for the flexibility for scheduled maintenance as well as unplanned shutdowns. However, a lean feed gas of this type will require low pressure conditions in the scrub column for proper separation of the refrigerant components from the main gas stream. If the reservoir pressure is high, this pressure must be reduced to support the separation process. Reducing this feed gas pressure reduces the liquefaction efficiency (power per unit of LNG) compared to liquefying at a high pressure. To produce the same volume of LNG, this reduction in efficiency is countered with booster compression (to raise the pressure prior to liquefaction) or by applying additional refrigerant compressor power; both solutions raise the power required per unit of LNG produced. If the NGL recovery is only required to support refrigerant makeup, any remaining NGLs can be reinjected into the liquefaction stream through a separate coil in the MCHE as long as the LNG meets product specifications.

A further complication arises when the heavy end of the feed gas contains a high amount of pentanes (C5) relative to hexane and heavier components. In this case, the condensate vapor pressure will be higher than the usual specification of 0.7 bar (10 psia). The remedy for this situation is to remove enough pentane from the condensate to reduce the vapor pressure, but then one needs to find a way to dispose of the pentane. Reinjecting the pentane into the LNG can make the LNG out of spec (on heating value or maximum allowable pentane), while selling the pentane as a product is difficult because of the small volume and high vapor pressure (making transport inconvenient). Under these circumstances, the material is either used within the plant as fuel or sent to a nearby refinery for further processing.

A feed gas containing additional heavy hydrocarbons would allow liquid separation in the scrub column at a higher pressure than the previous example. In short, a rich feed gas has the following design and operational advantages:

- Easier scrub column design and operation,
- Sufficient refrigerant make up quantities,
- High value NGL products for sale, and
- Feed gas that is easy and efficient to liquefy

The additional high value liquid products (LPG and condensate), provide additional revenue and improve the overall project rate of return. In general, the extra revenue for the additional products more than compensates for the extra equipment and construction costs for the “complicated” plant. Recent papers [5] discuss the cost impact of adding NGL recovery to a basic LNG plant. This additional cost must be
evaluated against the increased revenue to demonstrate the best total value for a specific project or opportunity.

In general, it could be said that a lean feed gas can cause more complications in the design and operation of an LNG plant than a rich feed gas. In other words, a lean or light feed gas complicates the LNG plant, and produces less total product revenue than a rich feed gas.

Myth: Lean feed gas is best as it results in simple LNG plants
Truth: Lean feed gas results in LNG plants that may be simple to construct, but result in less revenue and are challenging to design and operate

Summary: Current Myths About LNG

While the LNG community continues to grow, there are still myths about LNG that need to be brought to light. The existence of these myths is beneficial to promoting open and spirited debate which will encourage the development of LNG technologies. On the other hand, myths about LNG are detrimental to the industry if they increase the technical and commercial risk on actual projects.

Myths are perpetuated for a variety of reasons. It is natural to want to believe in stories about events or accomplishments that defy convention and will change the course of history. Through shared experience, we must continue to encourage debate of LNG myths in order to assure the success of future projects. In other words, LNG myths must be tested in order to be declared proven, possible, or phony.
References


