FLNG – History Does Not Repeat Itself, but It Does Rhyme

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KBR
The floating LNG (FLNG) business is in a new and exciting phase. After many years of envisioning the future of FLNG, the implementation phase is upon us. To be successful, FLNG project teams should learn the lessons from completed FPSO projects. At the same time, these teams must understand the aspects of FLNG that are unique. Teams that are solely familiar with onshore LNG projects should prepare to be surprised as familiar metrics and rules of thumb will not apply to FLNG.

The purpose of this paper is to discuss the FPSO development journey as it applies to FLNG. If we are to follow Mark Twain’s sage advice (as incorporated into the title of this paper), what lessons from the design of FPSOs will lead to the success of FLNG? Where are the potential traps?

We will explain the many FPSO lessons, compare FLNG against FPSO projects, and draw possible lessons for FLNG – both in execution and in technology. The biggest danger in this new industry is the idea of: “You don’t know what you don’t know”. Lastly, we will discuss the risks involved in FLNG projects and how these risks can be mitigated.

Specific topics include:

- The development of the FPSO industry
- Execution planning
- Schedule
- Size of facilities
- Safety
- Influence of process design and licensed technologies
- Recognized technical challenges
- Recognized execution challenges
- Operations and maintenance
Introduction

The concept of offshore liquefaction, or FLNG, is no longer a new idea. However, after fifteen or more years of studying FLNG concepts, there is not a single baseload FLNG project operating anywhere in the world. As the capital cost of onshore LNG projects has risen substantially since 2005, it appears that some FLNG prospects could become economically attractive as an alternative to onshore LNG. In the overall context of an opportunity, FLNG may be part of the most cost effective gas monetization solution. If the estimated capital cost of FLNG approaches that of onshore projects, what are the additional barriers to entry?

There are many opinions on why FLNG has not been yet been commercialized. These opinions commonly involve perceived risks that are large enough to stall concepts in the appraisal phase. Some of these risks include:

- Technical risk – FLNG may not be feasible
- Commercial risk – FLNG does not provide adequate rate of return
- Execution risk – FLNG is too complex to put together in today’s market

Each set of risks are valid causes for concern; but technical, commercial, and execution risks are present in all large industrial projects. The key to successful project implementation is the mitigation of risks, which is achieved by a proper project execution plan. Execution planning anticipates risks by applying the appropriate lessons of the past to new concepts and situations.

FLNG press releases often cite the familiar liquefaction process technology aspect of these projects. Liquefaction technologies are technically vetted entities that create natural divisions among concepts and owner/operator companies. For example, liquefaction technologies can separate concepts by plant capacity, refrigerant sources, and equipment selection. However, developing a new industry like FLNG requires a focus on the less familiar aspects of a project in order to mitigate true risks.

The quotation “History does not repeat itself, but it does rhyme” is often attributed to Mark Twain, who had a fondness for the odd saying that is laden with sage advice. If FLNG follows a familiar path like other large projects, should we take note of the history of onshore LNG or that of oil and gas FPSOs? If the future of FLNG rhymes with events in recent past, it is the lessons learned from FPSOs that will ring familiar when implementing the first baseload FLNG projects. However, once the first FLNG is towed to its destination, the project becomes an LNG plant.

Even though we will look to the history of FPSOs for guidance in developing FLNG projects, we must also review the recent history of the onshore LNG business in order to determine the viability of FLNG. Since FLNG is a new business that merges liquefaction and offshore technologies, a complete understanding of the issues is needed to maintain objectivity. Although the history of FPSOs will “rhyme” with FLNG, the proper mitigation of both FPSO and LNG risks will be essential to deliver a successful project. In order to focus on FPSO history and project execution challenges, this paper will not address LNG supply and demand, the commercial viability of FLNG, or any floating regasification schemes.
Onshore LNG Recent History

Since 2005, the cost of upstream oil and gas projects has been dramatically on the rise. From 2000 to 2008, upstream capital costs have increased nearly 100% [1]. Factors that influence an increase in capital cost include:

- Raw material price inflation
- Complex projects in challenging locations
- Coincidental industrial projects
- Finite contractor and material supplier capacity

In the past, LNG projects were once compact gas plants in industrial-friendly locations subject to favorable marine and shipping conditions. Over the last twenty years, large gas fields have become more difficult to find and potential site locations have become more challenging (e.g. Sakhalin, Snøhvit, Tangguh, Gorgon, etc). In addition, new issues facing onshore LNG developments include:

- Complex marine infrastructure (Jetty, material offloading facility, etc.)
- Greater distance of reservoir to shore
- Substandard soil conditions
- Arctic and arid environments
- High acid gas content / CO₂ sequestration
- Heavy hydrocarbon inventories

As a result, onshore LNG projects have transformed from liquefaction-centric gas plants to complex infrastructure-centric projects with a certain liquefaction capacity. In some cases, the estimated LNG train cost is 30% or less than the overall project cost.

The once useful comparative metric of $US per annual ton of production is currently meaningless. Comparing one LNG project versus another is difficult without using a common basis that contains the effect of infrastructure costs as a function of the overall plant capacity [2]. One of the goals for FLNG is to minimize these infrastructure costs to the level necessary for reliable plant operation in a marine environment. At a minimum, it is clear that FLNG combines gas treatment, liquefaction, storage, and offloading in a singular piece of infrastructure.

A recent strategy to develop onshore LNG projects has been the use of design competitions with two or more contracting entities. The design competition is a different approach for encouraging execution innovation, guaranteeing multiple EPC bids, and reducing CAPEX or life cycle cost for well established industries like onshore LNG. A successful design competition is based on full definition of the project requirements and principles along with fair set of rules in which to compete [3]. On the other hand, a competition allows limited flexibility for scope changes or significant technical changes. As a result, design competitions are not best suited for developing industries or first-of-a-kind projects.

Perceived FLNG State of the Art

The perceived state of the art of FLNG varies depending on the source of information. With many companies and consortia all vying to be first (or even second) to commercialize FLNG, a limited amount of public information leads to a distorted perception on the state of development of publicized projects and schemes. However, it is clear that many separate entities are proposing technical and commercial solutions to the FLNG puzzle.
There is no doubt that every formidable international oil and gas company has considered FLNG as a potential alternative to conventional onshore liquefaction. A first step in the evaluation of FLNG is to conduct conceptual studies to review concepts and compare capital cost estimates of defined accuracy. While these studies are technical in nature, a primary deliverable is the capital cost estimate. As a result, conceptual FLNG studies are often based on onshore LNG technical know-how combined with varying levels of information on hull and fabrication issues. Since estimate accuracy is a function of engineering detail (certainty of quantities, workhours, subcontracts, and schedule), the publicly stated cost of an FLNG project is subject to great variation. In addition, comparing FLNG cost estimates using onshore LNG metrics of $US/ton is irrelevant unless a comparable onshore option and estimate is technically developed for that exact natural gas asset.

Among the myriad of players in FLNG, there are definitive camps that pursue similar development paths. Some of these groups include:

- Large scale providers (high capacity FLNG)
- Alliance-based solutions
- Customized solutions
- Niche solutions

Large scale providers follow a path of bringing state-of-the-art onshore LNG to a marine environment. This philosophy utilizes the concept of maximum liquefaction capacity, via perceived economy of scale, by using sensible practice from onshore LNG and challenging the limits of current FPSO size and topsides weight. Large capacities will provide the highest annual revenues with the challenge of building the largest FPSOs in the world. For example, our study experience indicates that an FLNG capacity of 5 Mt/a will require a hull size larger than any FPSO that has been built (see Table 2 for example FPSO dimensions).

Alliance-based solutions rely on a consortium of companies to provide parts of the total FLNG solution. For example, an FPSO owner/operator could align with a liquefaction technology provider and/or a shipbuilder or module fabricator. The net technical capability of the consortium is high, while the experience in developing a full-field LNG FPSO solution does not reside in a single part of the alliance. As a result, the alliance is viewed as strong in the arena of public opinion.

Developers pursuing customized solutions have the greatest degree of freedom in applying technology and experience to FLNG. This freedom is further enhanced if the developer has extensive LNG and offshore experience. On the other hand, technical freedom results in a challenging series of decisions to face during appraisal and selection stages. The road to a customized solution could be an optimal path if the journey is forged by a developer with the technical know-how, finances, and perseverance to complete the quest. There are no shortcuts to a customized solution; therefore, the developer is faced with a significant challenge to find the right concept and execution strategy before fully committing to FLNG.

Niche solutions cover unique methods to penetrate the FLNG market. In some instances, the actual "first mover" in FLNG may be a niche solution. This area covers a wide spectrum of solutions, including smaller LNG capacities, conventional LNG carrier-based solutions, unconventional hull designs and shapes, and unique liquefaction technologies.

Many players in FLNG face a challenge of how to move their project forward. As of this writing, very few opportunities are developed to the degree of estimating and execution certainty needed to fully sanction the project. The execution risks of a multi-billion dollar industrial project lie in the technical and commercial details. Many FLNG concepts
have not addressed these details because of the colloquial concept of “You don’t know what you don’t know”. There has not yet been an FLNG front end engineering design (FEED) project based on a fully vetted proven concept, so there is a strong need to execute a high quality FEED to reduce technical risk and commercial uncertainty. As a result, all developers should plan how to structure a high quality FEED while learning from the history of FPSOs and LNG projects in order to further commercialize their solution.

**FPSO History and FPSO-Today**

The move toward the design of the first oil and gas FPSOs in the 1970s is similar to the current opportunities facing the LNG industry. New hydrocarbon assets (crude oil and associated natural gas) that were once found onshore and in convenient locations were proving difficult to find. In order to augment existing oil production and supplement reserves, companies had to look to offshore locations; first to platform-based solutions in shallow water locations, and then to deep water reservoirs.

As attractive hydrocarbon reserves were found farther from shore, the FPSO concept was developed in order to monetize these assets by crude oil transport to shore via shuttle carriers. On many occasions, some degree of topsides processing was involved. These first FPSOs were ideal for areas such as the North Sea, Brazil, and Western Africa, where there was either a local demand for crude oil products or an economic benefit for export.

The beginnings of the FPSO industry and the current development path of FLNG are quite similar. As natural gas assets (including associated gas assets) are found further offshore, conventional onshore gas processing is becoming increasingly challenging and more costly. With the experience of a large fleet of LNG carriers in service, applying the historical lessons of FPSOs seems to be a natural fit for FLNG.

The first FPSO projects were uniquely challenging in merging traditional oil and gas recovery with the experience gained from designing shallow water offshore structures. The movement to deeper water was a historical step change in the hydrocarbon industry, as this new business had few established rules and needed exceptional technical experience, execution leadership, and the passion for this new enterprise. These mega-projects have a common “first-of-a-kind” nature where technical risk is tempered by sound execution and risk management.

As the FPSO industry matured, so did the opportunities to push the limits of vessel size and volumetric capacity. As of this writing, one of the world's largest FPSOs is the Kizomba A (operated by ExxonMobil) located in 1200 meters of water and 150 miles offshore Angola. The vessel has a capacity of 2.2 million barrels (equivalent to 350,000 m³ of liquid storage) and has hull dimensions of 285 meters long, 63 meters wide, and 32 meters high.

The development of the modern FPSO and associated technologies are the result of innovative teams overcoming great technical challenges; these initial efforts were necessary in order to monetize offshore oil and gas reserves in deep water and were often subject to considerably challenging marine conditions. The need to augment global natural gas reserves along with the demand for LNG is clear. The question of FLNG is not “if” but “how”.

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The Evolution of Onshore LNG to FLNG

One logical path to FLNG involves the transition of known onshore concepts to a new marine environment. This evolution is in progress even without a current LNG FPSO in fabrication. In fact, the real road to FLNG began as early as 30 years ago.

The familiar evolution to FLNG takes a very logical path:

Onshore LNG → Modular LNG → Offshore LNG

Less complex project → more complex project

Baseload onshore LNG projects, still quite commercially viable, have a history going back to the Camel project in Algeria from 1964. Onshore LNG facilities, based on the degree of infrastructure required, are still commercially viable today. However, in areas where labor or infrastructure costs are high, some developments have considered modularization construction techniques.

The popularity of modular construction began to rise in the 1970s [5]. Modular construction was often used for areas with challenging weather patterns such as for oil and gas fields along the North Slope of Alaska. With regard to LNG, this philosophy was implemented for projects such as Snøhvit LNG in Norway. In more temperate climates, modularization allowed the pre-fabrication of Train V of the Northwest Shelf LNG facility to take advantage of modular construction productivity and efficiency. As a result, modular design is proposed for future LNG projects such as Gorgon LNG, Inpex LNG, and many other projects. The design of such modules will be based on the design fundamentals and expertise gained from offshore oil and gas projects, including FPSOs.

The next extension of onshore LNG modularization is the design of LNG related equipment for offshore operation. LNG projects are often associated with large scale power systems, piping, and equipment that provide a unique challenge over simpler technologies. In addition, offshore modules must be designed for both operational and transportation loads when operating in a transient environment. As a result, historical oil and gas projects in challenging locations have helped develop the potential for FLNG.

How FLNG Differs from Traditional FPSOs

Although there are many familiar themes in the development of both FPSOs and FLNG, there are several differences that make FLNG unique. These differences are primarily categorized in the areas of overall size/scale and process technologies. The successful development of FLNG projects is based on identifying the risks associated with these differences and allowing for successful project execution.

Typical LNG Carrier Dimensions

<table>
<thead>
<tr>
<th>Storage Volume (m$^3$)</th>
<th>Length (m)</th>
<th>Width (m)</th>
<th>Depth (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>165,000</td>
<td>286</td>
<td>44</td>
<td>26.2</td>
</tr>
<tr>
<td>175,000</td>
<td>286</td>
<td>45.6</td>
<td>26.6</td>
</tr>
<tr>
<td>215,000</td>
<td>302</td>
<td>50</td>
<td>27</td>
</tr>
<tr>
<td>265,000</td>
<td>332</td>
<td>53.8</td>
<td>27</td>
</tr>
</tbody>
</table>

*Table 1. Dimensions of LNG Carriers*

The most noticeable difference in developing FLNG is with the relative size of the vessel necessary in order to make an impact on the LNG market. For the range of FLNG providers previously discussed, LNG capacity ranges from 1 to 8 Mt/a. The global LNG
trade for 2008 was 174 Mt/a [6]. At the lower end of this range, the LNG traded is about 0.5% of the world capacity; as a result, the volume could be traded on either a long-term or speculative basis in order to fill small gaps in worldwide trade volumes. In terms of hull dimensions, the vessel size is comparable to that of a medium sized LNG carrier. A sample list of LNG carrier dimensions is listed in Table 1.

At the higher end of the FLNG capacity range, the project would fulfill incremental energy demands in dedicated markets via the use of traditional long-term LNG contracts. However, with increased liquefaction capacity, the length of purpose-built barges could grow in excess of 500m. This increase in length is attributed to both the topsides area required and the liquids storage volume required based on selected shipping logistics. To some extent, the size of a large FPSO is similar in scale to a modest capacity FLNG; as a result, a large capacity FLNG will push the current boundaries of FPSO size and scale.

A sample list of FPSO hull dimensions is provided in Table 2. Looking at this data, there are manufacturing and commercial barriers that limit the dimensions of these hulls. For example, the width of an FPSO is limited by the drydock capabilities of the largest capacity shipyards. These drydocks cannot “expand” in width for one specific project. From Table 2, the maximum width for FLNG to fit the current manufacturing experience is 63 meters; however, there have been several crude oil carriers delivered with dimensions of 380m x 68m [4]. These dimensions are within the tolerance for the largest capacity LNG carriers, delivered in 2008, shown in Table 1.

### Sample FPSO Dimensional Characteristics

<table>
<thead>
<tr>
<th>Vessel Name</th>
<th>Topsides Weight (t)</th>
<th>Length (m)</th>
<th>Width (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Terra Nova</td>
<td>10,000</td>
<td>291</td>
<td>45.5</td>
</tr>
<tr>
<td>White Rose</td>
<td>13,500</td>
<td>258</td>
<td>46</td>
</tr>
<tr>
<td>Girassol</td>
<td>20,000</td>
<td>300</td>
<td>59.6</td>
</tr>
<tr>
<td>Greater Plutonio</td>
<td>23,000</td>
<td>310</td>
<td>58</td>
</tr>
<tr>
<td>Belanak</td>
<td>24,000</td>
<td>285</td>
<td>58</td>
</tr>
<tr>
<td>Bonga</td>
<td>34,000</td>
<td>295</td>
<td>58</td>
</tr>
<tr>
<td>Agbami</td>
<td>35,000</td>
<td>320</td>
<td>58.4</td>
</tr>
<tr>
<td>Dalia</td>
<td>37,000</td>
<td>300</td>
<td>60</td>
</tr>
<tr>
<td>Akpo</td>
<td>40,000</td>
<td>310</td>
<td>61</td>
</tr>
<tr>
<td>Kizomba A</td>
<td>Not Available</td>
<td>285</td>
<td>63</td>
</tr>
<tr>
<td>Kizomba B</td>
<td>Not Available</td>
<td>285</td>
<td>63</td>
</tr>
</tbody>
</table>

### Table 2. Hull Dimensions of Operating FPSOs

In addition to vessel width, the vessel length can be affected by shipyard limitations. Comparing Tables 1 and 2, the current upper range of vessel length is 330 meters, with minimal experience of one shipyard at 380 meters. This maximum dimension allows for efficient manufacturing of multiple carriers and/or FPSOs within a given shipyard. Extending the length of the FLNG, based on additional LNG capacity, module complexity, turret location, safety separation distances, or additional liquids storage will create execution challenges for shipyards accustomed to building oil and gas FPSOs, LNG carriers, crude oil carriers, containerships, bulk carriers, and naval ships. However, if the market for high value transportation vessels becomes less attractive than for the potential future for FLNG, the opportunity to build longer floating vessels will become possible.

Another difference between FLNG and an FPSO is the amount of topsides processing that is required to produce the valued cargo. For an FPSO, the cargo is crude oil and for
FLNG, it is on-spec LNG product. The amount of topsides processing required to produce LNG is significantly greater than that for FPSOs.

The goal of a traditional FPSO is to produce a certain capacity of stabilized crude oil and provide enough storage in order to support a predetermined number of offloading tankers. This crude oil is a high value commodity that requires further processing onshore. As a result, the minimum amount of offshore processing is included in order to guarantee a suitable end product. This processing includes oil treatment (separation, dehydration, desalting, and stabilization) plus the treatment of separated water and natural gas that are characteristic of the reservoir. Water and natural gas are often reinjected to enhance oil recovery while any exported natural gas is treated for its water dew point and sometimes for H₂S.

The goal of FLNG is to export a valuable commodity that has a strict product specification that requires no further processing onshore. The actual liquefaction of natural gas requires a highly purified feedstock compared to that required for oil extraction or even oil refining. Natural gas suitable for liquefaction must be treated for CO₂ (to <50ppm), water (to < 1ppm), H₂S (to < 4ppm), and the removal of all C₅+ (< 0.1%) components that would freeze during refrigeration. In addition, in order to make LNG, one must also store LPG and condensate, which are natural end products from liquefaction. While most discussion of FLNG revolves around liquefaction process technology, the integration of upstream processing units for an entire FLNG solution must not be ignored.

![Belenak LPG FPSO – A Precursor to FLNG](image)

In a gross oversimplification, an FLNG is similar to a FPSO with a “refinery” added to the topsides processing scope. As a result, the lessons learned from the design of offshore equipment, module and hull interfaces, and project execution risks will be applicable for FLNG, but do not answer all of the potential questions. As of April 2008, there were 121 FPSOs in operation with 53 on order. Of these vessels, 70 were new builds and 104 were converted hulls [7]. Since FPSOs target oil and gas recovery, the hulls can be converted from existing crude oil carriers. Due to the demands of LNG topsides and to develop a safe and reliable industry, it is expected that all of the first FLNG vessels will be new builds.

**What is a “Typical” FEED?**
The proper definition of project scope, deliverables, and estimating is necessary to develop a well-defined and economically viable project. The process for achieving scope definition is commonly known as Front End Loading (FEL), but is also branded by other companies using similar methods of exploring alternatives and making critical decisions. Initially, the term FEL was defined as “front loading” operations and maintenance experience to the preliminary stages of engineering development. For projects yet to receive EPC funding (i.e. final investment decision, or FID), the FEL process is often divided into three phases: FEL-1, FEL-2, and FEL-3 [8]. These project stages of conceptual engineering, feasibility study, and scope definition improve the potential to achieve a well-defined project scope and estimated cost (more stages may occur in proprietary FEL programs). A common estimating goal at the end of FEL is an accuracy range of +/- 10%. The key to obtaining this accuracy is the quality of the engineering and decision-making invested prior to FID.

### Execution Metrics for Project Development

<table>
<thead>
<tr>
<th></th>
<th>Conceptual (FEL-1)</th>
<th>Feasibility (FEL-2)</th>
<th>Definition (FEL-3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost Estimate Accuracy</td>
<td>+/- 40 %</td>
<td>+/- 25 %</td>
<td>+/- 10 %</td>
</tr>
<tr>
<td>Cumulative Engineering Hours Spent</td>
<td>1 - 5 %</td>
<td>5 - 15 %</td>
<td>15 - 30 %</td>
</tr>
<tr>
<td>Contingency</td>
<td>15 - 20 %</td>
<td>10 - 15 %</td>
<td>8 - 12 %</td>
</tr>
</tbody>
</table>

Table 3. Target Metrics for Project Development Phases

Using this terminology, a project “FEED” covers phases FEL-2 and FEL-3, the feasibility and definition phases. These phases are co-led by the client and engineering contractor in order to make project decisions that have the greatest positive influence over the life of the project. The life of the project includes operation and maintenance phases in addition to the EPC and commissioning phases. Since a full-scale FLNG still does not exist, what is a proper FLNG FEED in order to limit exposure to cost and schedule risk? What is required in terms of workhours and duration? Answers to these questions lie in the lessons of the past; but which history should we follow: 40 years of onshore LNG or 30 years of operating FPSOs?

Onshore LNG project execution has greatly evolved over the last 40 years. The substantial growth in the production of LNG since the 1990s has led to technical and commercial innovations to increase LNG train capacity in some of the most challenging locations of the world. As a result, FEED metrics are familiar among the companies involved in the design of LNG projects. A range of these metrics is listed in Table 4.

<table>
<thead>
<tr>
<th>Project Type</th>
<th>FEED Workhours</th>
<th>FEED Schedule (Months)</th>
<th>Project Characteristics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small Scale LNG</td>
<td>Low to Medium</td>
<td>6 - 12</td>
<td>Proven technology and modest or peakshaving capacity, industrial location, easy access to feed gas, labor, and material</td>
</tr>
<tr>
<td>Medium Scale LNG</td>
<td>Medium</td>
<td>9 - 14</td>
<td>Proven technology and capacity range, predictable feed gas, familiar logistics, medium infrastructure</td>
</tr>
<tr>
<td>Large Scale or Challenging LNG</td>
<td>High</td>
<td>12 - 18</td>
<td>Advanced technology, enhanced capacity, challenging feed gas conditions, heavy infrastructure, environmental challenges, multiple contracting partners</td>
</tr>
</tbody>
</table>

Table 4. Range of FEED Metrics for Onshore LNG Projects

For a well-developed industry like onshore LNG, a good quality FEED (and resulting EPC estimate and schedule) is a function of the project characteristics and not a simple
correlation of $US/ton of capacity [3]. Projects with familiar technologies in familiar locations with predictable reservoir characteristics and ample labor are far different than projects with challenging characteristics at every turn. A high quality LNG FEED will include definition of technologies, operations, and logistics necessary to obtain high confidence in the cost estimate and execution schedule. Without consideration of the unique challenges of a given project, a common perception is that an onshore LNG FEED is 9-12 months with a predictable range of workhours.

Similar to LNG, FPSO project execution has evolved over its history. The growth in this industry was led by the technical and execution innovations of shallow water projects including fixed platforms and gravity based structures (GBS) combined with a robust crude oil tanker fleet. These innovations were based on both the shallow waters of the Gulf of Mexico and the harsher conditions of the North Sea. Moving from fixed to floating structures, FPSO projects have pushed the limits of water depth and capacity in order to produce more barrels of oil per day, at higher storage capacities, with additional topsides processing. In addition, the FPSO market has moved from solely oil field development projects to integrated gas and LPG projects such as the Belanak and Sanha projects. The feasibility and definition phases of FPSO projects vary similarly with the LNG industry; a range of these FEED metrics is listed in Table 5.

<table>
<thead>
<tr>
<th>Project Type</th>
<th>FEED Workhours</th>
<th>FEED Schedule (Months)</th>
<th>Project Characteristics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small Scale FPSO, Redeployment, or Hull Conversion</td>
<td>Low to Medium</td>
<td>6 or less</td>
<td>Based on converted oil tankers. Oil production up to 50,000 bpd</td>
</tr>
<tr>
<td>Medium Scale FPSO or VLCC Conversion</td>
<td>Medium to High</td>
<td>6 - 9</td>
<td>Based on converted oil tankers or hull based on existing and modified tanker designs. Oil production between 50,000 to 150,000 bpd</td>
</tr>
<tr>
<td>Large Scale FPSO</td>
<td>High</td>
<td>12 and over</td>
<td>Purpose built hulls. Oil production over 150,000 bpd. Integrated hull and topsides design, suitable as central processing facility in large deep water fields</td>
</tr>
</tbody>
</table>

Table 5. Range of FEED Metrics for FPSO Projects

A high quality offshore FEED will include definition in the following areas: project interfaces (design and physical), concept decision making, hazard identification, operational design, estimating, compliance planning, and execution planning [9]. Similar to LNG, not all FPSO projects are created equally. Regardless of the topsides processing, FPSO projects with differing wind, wave, water depth, storage, and execution characteristics will vary widely and are not a simple metric of the topsides weight or storage volume. Limiting the investment in an offshore FEED can lead to rework in detailed design that creates delay and/or additional cost in the fabrication yards or while positioned offshore.

Both LNG and FPSO projects have lessons learned from conceptual studies and scope definition, such that EPC projects have become cost competitive and open to healthy competition. However, even these traditional businesses are facing challenges with economies of scale and the search to effectively monetize hydrocarbon reserves. A short list of these challenges is listed in Table 6. With the capital cost of upstream hydrocarbon projects sharply rising since 2005, it is imperative to have a high quality FEED, especially for projects that have first-of-a-kind technical, execution, or commercial risks. Ironically, both industries have recent project examples that were subject to gross cost and schedule inflation. Do we want to take undue execution risk with an insufficient FLNG FEED?
Current Challenges for Traditional Product Lines

<table>
<thead>
<tr>
<th>FPSO Industry</th>
<th>Onshore LNG Industry</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conversion of larger / older hulls</td>
<td>Economies of scale above 6 MTPA</td>
</tr>
<tr>
<td>Deep water issues</td>
<td>Infrastructure cost escalation</td>
</tr>
<tr>
<td>Operation in cyclonic conditions</td>
<td>Environmental challenges</td>
</tr>
<tr>
<td>Asset security near shore</td>
<td>Limitations of technical labor</td>
</tr>
<tr>
<td>Finite lump sum EPC competition</td>
<td>Finite lump sum EPC competition</td>
</tr>
<tr>
<td>Cost escalation and control</td>
<td>Cost escalation and control</td>
</tr>
</tbody>
</table>

Table 6. Factors Affecting Future LNG and FPSO Projects

What is a High Quality FLNG FEED?

A high quality FLNG FEED should incorporate the successes and lessons learned from these two well established industries. FLNG is a new and emerging business; the focus should not be overly dominated by either LNG or offshore thinking. However, we naturally tend to gravitate to what we know, as opposed to the unknown. To date, some FLNG opportunities have been led by experienced shipping companies but more are led by LNG producers targeting stranded reserves and traditional markets. As a result, FLNG is often thought of as an extension of either LNG know-how or FPSO know-how, with a less intensive regard to the “other side”.

Objectively, the goal of the FLNG FEED is to study and define the project in order to obtain technical and estimating certainty necessary in order to advance the project to FID. Based on the challenges faced by future onshore LNG and FPSO projects, do we know all of the answers to the questions posed for marinization of an LNG train or multiple trains?

<table>
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<th>Elements of a High Quality FLNG FEED</th>
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<td><strong>Sample Activities for FPSO FEED</strong></td>
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<td>Motions and accelerations defined</td>
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<td>Identification of turret vendor and interfaces</td>
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Table 7. Elements of a High Quality FLNG FEED

Reviewing Table 7, one immediately raises questions about the feasibility of design, operability, size, and scale of a floating liquefaction plant. All of the challenges of
working offshore are difficult enough; FLNG considers a world class arrangement of gas processing, power plant, and refrigeration equipment that must operate with a high degree of availability and safety. The path toward executing a high quality FEED is well within sight for LNG producers that have reviewed potential markets and technologies, but do the workhour and schedule metrics from onshore LNG apply when considering the scope of this high quality FEED?

As mentioned for both onshore LNG and FPSO projects, a primary goal during FEED is to improve confidence in the design for operation, execution strategy to assure schedule, and cost estimating that affects competition and the best use of capital. In structuring a high quality FEED, would the activities from Table 7 require more or less definition than historical projects?

One of the biggest changes in mindset in planning an offshore FEED is the level of engineering necessary to support a ±10% cost estimate. Onshore LNG projects have a long history of correlating the engineering activities necessary to support an estimate. Capable contractors wield this expertise based on this known set of activities adapted to site specific requirements. As a result, the technical and estimating assumptions for onshore LNG project are based on decades of experience along with a keen sense of current material and labor markets.

FLNG projects often claim to be simple and quicker to construct based on eliminating remote onshore construction labor and infrastructure such as temporary facilities, marine systems, and LNG storage. However, moving the fabrication of an LNG plant to an efficient industrial shipyard ignores the design certainty necessary for the actual LNG plant to be supported by a floating hull.

An offshore estimate is based not only on the equipment defined by the process and captured on P&IDs, but its total weight. For onshore LNG, foundation calculations are not a critical path item, but the topsides weight estimate as well as the management of that weight during EPC is critical to the structural support and stability of the hull. If design changes allow equipment or systems to increase in weight, the entire project is affected. For example, the deliverables for an FPSO FEED include pipe routing definition that would not be part of the onshore LNG FEED scope. The level of engineering detail is much greater offshore in order to assure certainty of topsides weight.

As a result, a high quality FLNG FEED must define equipment to a greater detail than for onshore plants. For example, an onshore plant may require a pump of a certain size and type, but an offshore plant will estimate the pump size, model number, weight, and support criteria in order to design the support module. Consequently, equipment selection has a cascading effect on the entire system design which determines the primary structural steel weight necessary for each module. While an onshore LNG estimate can be factored from items such as equipment count and labor cost, offshore LNG estimates are factored by equipment and bulk material weights critical to the module design, fabrication schedule, labor cost, and hull size.

The extra effort needed to define the weight of equipment and systems bulk materials results in workhours not commonly thought to occur during FEED (but common for FPSOs). In comparison to onshore LNG, a high quality offshore FEED would contain 30% of what was scheduled as detailed engineering for an onshore project. This engineering is necessary to prevent weight escalation which is proportional to cost escalation and schedule creep, possibly resulting in the project not meeting milestones or expectations.

The total system weight includes piping design down to a line size needed to instill confidence in the module sizes and weights. For example, it is suggested to model all piping down to at least 10” during FEED. At this level, this process enables over 70% of the piping weight to be extracted directly from the 3D model. Where lines are stress or
interface critical, piping sizes down to 4” are modeled. In addition to weight implications, the packing density of modules (equipment, piping, and structural steel) has a yet to be determined effect on safety, which, if proven to be detrimental, may require re-engineering of layouts.

One of the implications of a high quality FLNG FEED is a misconception of cost competitiveness of the project. However, reduced scope development or a reduction in FEED workhours will add unneeded contingency to the cost estimates from all engaged parties. High levels of contingency and uncertainty will result in a lack of competition for the EPC phase for all but reimbursable projects.

How are we to interpret the press releases over the last few years stating that FLNG will significantly reduce the time to deliver the first cargoes of LNG versus an onshore LNG plant? First, due to the varying scope of all large complex projects, it is difficult to compare one LNG project to another as “not all plants are created equal” [3]. Some LNG projects are train expansions, have complex infrastructure, or have varying process and utility scope that significantly affect cost and schedule.

Similar to FPSOs and onshore LNG, FLNG concepts will vary widely and no two projects will be similar. FLNG projects will vary in capacity, using different technologies, and will be based on different hull concepts with different containment and loading systems. In addition, these FLNG concepts will be subject to the feed gas composition variation that separates all LNG projects in scope. The true success of FLNG will depend on the path to FID: taking either the high quality FEED or the minimalist path will result in different outcomes regarding project cost and implementation schedule.

Reduction in scope can also occur during pre-FEED or conceptual development. As mentioned in the section “What is a typical FEED?” the investment in scope definition will be rewarded during later stages of execution. As a result, isn’t it imperative to perform a high quality (if not exhaustive) FLNG FEED in order to provide the certainty of design and capital cost that is warranted for a first-of-a-kind project of this magnitude? Ignorance of the critical design issues by ignoring the 800lb gorilla in the room illustrates the concept of “You don’t know what you don’t know.”

**FLNG Technical Issues**

Another integral part of bringing together an FLNG involves resolving the design issues of topsides process technologies, equipment, and module design. Although traditional FPSOs can have sizeable gas processing facilities (e.g. up to 500 million standard cubic feet per day), baseload liquefaction is a major extension from offshore oil and gas processing. A “standard” feed gas flow rate of 500 MMSCFD would produce approximately 3 Mt/a of LNG; this production is less than the production capacity of nearly every LNG train under construction in 2009 (4.0 to 7.8 Mt/a). For larger LNG production capacities, the expected topsides weight of FLNG will exceed that of the large FPSOs in Table 2.

Successful conceptual design leading to a high quality FEED requires acknowledgement of the issues and difficulties of offshore gas processing and liquefaction and not a dance around the issues with conceptual photos. Since most definition occurs during FEED, a proper conceptual study (or pre-FEED) will formulate a design register to capture the issues that require more intensive study. After the review of a handful of technical issues across multiple concepts, one may question if any company or joint venture has actually attempted a quality FLNG FEED.
As seen in Figure 2, a liquefaction plant with a one or two stage refrigeration system is comprised of many interfacing units. In addition, nearly all stranded gas fields will require three types of product storage: LNG, LPG, and condensate. It is evident that the total scope of an LNG plant, which occupies well over 100 acres onshore and hundreds of pieces of equipment, will be a challenging task. Ironically, instead of addressing the execution challenges of large complex projects, most public discussion of FLNG revolves around liquefaction process technology.

The Role of Process Technology

There are many liquefaction process technologies suitable for FLNG. These technologies can be categorized in the following areas:

- Inert refrigerant expander technologies (e.g. Nitrogen processes)
- Dual expander technologies (e.g. N2 and methane)
- Single Mixed Refrigerant technologies (SMR)
- Dual Mixed Refrigerant technologies (DMR)
- Traditional baseload technologies (C3-MR and Cascade)

Each subset of liquefaction technologies are different based on overall process efficiency, refrigerant composition, number of refrigerant cycles, and the critical equipment used in the process. Familiar metrics for onshore LNG plant efficiency (e.g. 35 MW per Mt/a of LNG) are based on cascade and MR technologies while other processes provide additional design flexibility at a lower process efficiency. With the number of processes available, what is the best solution for FLNG?

Objectively, all available technologies could be applied for FLNG. Each technology, along with its refrigerant and equipment basis, could be appropriate within the agreed principles of availability, operability, efficiency, and safety for use offshore. However, the weighted evaluation criteria used during the liquefaction process selection study will determine that one process is the best solution for a specific project. Regardless of the preferred liquefaction process technology, the important issues for FLNG lie with the equipment and interfaces of the flowsheet, and not the brand name of the scheme.

Once one moves beyond the name of the liquefaction process, one can begin to look at the technical challenges associated with designing FLNG topsides. Since the answers to these challenges are determined during FEED, it is unlikely that many FLNG proposals have fully uncovered the list of design and risk issues. During conceptual studies, a design register can be populated with the issues that must be faced during a high quality FLNG FEED. Significant progress has been made in this area by the successful design and construction of the Sanha and Belanak LPG FPSOs which have been operational since 2006. Although FLNG is an additional step beyond LPG processing, it is imperative to discover the technical risks for baseload offshore LNG. Again – “We don’t know what we don’t know.”
The Role of Equipment

One of the challenges in the execution of FPSO projects is the potential growth in topsides weight during the EPC phase. The key to mitigating the growth in topsides weight is to thoroughly define the amount of processing and refrigeration equipment during FEED while conforming to the expectations of process efficiency, availability, operations, and maintenance. Often, the drive to reduce equipment count (and module weight) is in direct opposition to the availability targets for onshore LNG.

Similar to a traditional value engineering exercise, the resolution of equipment count revolves around defining essential vs. non-essential equipment. Certain items or spares may not be essential to the actual process under normal operation, but may be essential for higher availability targets desired for FLNG. As a result, FLNG design competitions could result in minimally based facilities in order to limit topsides weight and capital cost as only the competition evaluation criteria is used to measure success. Consequently, since the design of FLNG is neither commonplace nor consistent among companies, design competitions or competitive FEEDs may not provide the intended value to the owner and operator of the facility.

In general, there will be more equipment required for FLNG than for FPSOs. Natural gas for an FPSO is usually treated only for water dew point and H\textsubscript{2}S as this gas is often reinjected to the well or sent onshore for additional processing. In addition, FPSOs treat associated gas in low feed gas quantities (150-300 MMSCFD) whereas larger FLNG projects require much higher feed gas flow rates to support capacities above 2 Mt/a.

There are some basic rules for equipment layout that are derived from decades of FPSO experience. Some of these issues include: locating horizontal vessels on the longitudinal axis to limit roll; installing perforated baffles in equipment to dampen the liquid turbulence in vessels; care with the design of gravity drains and seals under vessel motion; the accommodation for the sagging of the vessel deck on equipment supports and piping flexibility; pressurized liquid distributors in columns; and the design of level instruments for columns and tanks.

The effect of hull motions on equipment can be far more severe than initial perceptions. For example, it is easy to determine the motion at the top of a fractionation column using simple geometry. Even when the column is mounted near the centerline of the hull, the relative motion is a function of its height from the waterline and not from the support deck. For a 40m tall tower under a 2° maximum roll, the top of the vessel could move relative to a datum of 25m below the point of support, producing a maximum movement of 4.5m from side to side. Obviously, the actual design movement under maximum operating conditions is a function of the metocean criteria on location; however, critical safety systems, rotating equipment, and utilities (although not supported high above deck) must operate under more extreme pitch and roll criteria.

AGRU and Dehydration Equipment

An FLNG process unit that will be sensitive to motion is the acid gas removal unit (AGRU), which is required to remove CO\textsubscript{2} that would freeze in the liquefaction train. The AGRU contains one of the largest and heaviest vessels in an LNG facility, the AGRU absorber. The design of the AGRU is such that the effluent gas stream must be below the CO\textsubscript{2} solubility limit of 50 ppm while also removing H\textsubscript{2}S to levels below 4 ppm. This specification is much tighter than that needed for gas reinjection or pipeline transportation for onshore processing. As a result, the absorption process must work under the full range of operational motion to protect downstream cryogenic equipment from excessive CO\textsubscript{2}. 
Under static tilt or dynamic roll, the AGRU system could suffer mal-performance by insufficient solvent contact with the natural gas. As an example, if 1% of a feed-gas (which has a CO₂ concentration of 2%), slips through the absorber without contacting any liquid, this would represent a minimum CO₂ in the treated gas of 200 ppm – 4x the solubility limit of 50ppm. As a result, proven technologies onshore are not fully proven technologies offshore, especially where deep CO₂ removal is mandatory [10]. Similar to the AGRU, systems such as the dehydration unit must be designed to meet the stringent water specification of 1 ppm for the duration of its operational cycle (usually 8 hours).

An additional consideration for the AGRU is the variation of feed gas composition either during operation or for future relocation of the FLNG. At present, the design of the AGRU to meet tight CO₂ specifications is based on known feed gas compositions and amine circulation rates, not unknown compositions, consistent fluctuations, or educated guesses. The design for wide AGRU operational flexibility is not standard for onshore LNG and will become a unique challenge in the offshore arena.

Liquefaction Equipment

One of the often debated design challenges for FLNG is the design of the liquefaction module. The specific equipment within the liquefaction module is a function of the process technology and the train size. The list of equipment in this module would include most of the following: refrigerant compressors, refrigerant companders, compressor drivers (turbines or motors), main cryogenic heat exchanger, pumps, intercoolers, drums, hydraulic turbines, and/or JT valves. Of this equipment, the most widely discussed equipment is the main cryogenic heat exchanger (MCHE).

The design and operation of the MCHE depends on the selection of the liquefaction process technology and licensor. With the currently available process technologies referenced in this paper, the two types of MCHE are the plate fin heat exchanger (PFHE) and the spiral wound heat exchanger (SWHE). Both types of exchangers are used in onshore LNG projects, but much debate exists about which equipment is best suited for FLNG.

Many papers have been written about the design and operational benefits of both types of MCHE onshore, but there are currently two divided camps on this issue for FLNG. As a result, the optimal choice of MCHE is still under debate. Both options are appropriate for onshore plants, but the full evaluation of performance for marine conditions with high availability is yet to be tested. In addition, the operational risk of the liquefaction module must be determined during a high quality FLNG FEED.

The Role of Train Size

For all but the smallest FLNG concepts, the topsides design must address the role of LNG train size in order to meet the target LNG production rate while setting the plans for module size and layout. Similar to the MCHE, the train size is a function of the liquefaction process technology, although the scalability of each technology has its practical limits in any installation. The main decision regarding LNG train size is single vs. multiple trains.

As with most design challenges, there are two philosophies regarding train size that correlate with onshore LNG paradigms. Arguments have been made regarding the economies of scale for larger trains against two trains of 50% capacity [3]; however, the application of expander-based liquefaction technology may require 5 or more trains to meet a capacity target of 5 Mt/a. While multiple FLNG trains will allow a great deal of turndown under intermittent feed gas supply, the repetitive nature of the multiple trains
will increase the equipment count which will affect the overall maintenance program. Commercially, it may appear that bigger is often better or more economic; but the issues associated with the largest LNG trains (over 5 Mt/a) will compound the module design with larger equipment and piping. For either decision, the application of process technology and train size is a fundamental issue to be explored early in the conceptual development phase.

**Liquid Storage and Loading**

Although LNG carriers have been safely transporting LNG for over 40 years, these carriers operate in either an empty or full condition. FLNG will naturally have variation in day-to-day storage volume as a function of the production rate and the logistics of shipping LNG to multiple markets. In addition to the traditional storage for LNG carriers, FLNG projects must store all liquids produced onboard, including LNG, LPG, and condensate. Storing multiple liquids will affect the maximum amount of LNG storage allowed for standard carrier-based solutions while extending the hull dimensions for purpose-built ships. Innovative methods of cargo transfer and offloading can optimize the challenges of storing multiple products in partially filled tanks. With regard to tank construction and operation, many publications have addressed offshore storage in great detail.

Offloading LNG to traditional carriers is another unique design issue. Traditional side by side (SBS) loading using conventional marine loading arms uses standard equipment that is applicable for benign loading conditions. However, the relative movement between two floating bodies is more challenging than the movement along side a fixed marine terminal. For tandem loading concepts, newer technologies using flexible hoses connected to bow mounted carrier manifolds allow greater degrees of freedom but require dedicated changes to LNG carriers and additional testing of the tandem loading hardware which will limit the number of vessels that may offload from an FLNG.

**The Role of Hull and Marine Systems**

The design of the hull, turret, risers, and mooring system is a significant challenge regardless of the specifics of topsides processing. In review of the components of FLNG, it is certain that the hull will be either similar or larger than the existing LNG carrier fleet. Similarly, the turret and mooring system is a function of the amount of topsides processing, which will be comparable or heavier than the weights listed in Table 2.

Even for LNG carrier (LNGC) based FLNG solutions, the hull cost will be higher than an LNGC of similar capacity since the hull design must accommodate the topsides module weights and needs to provide fatigue performance commensurate with a 40 year design life. The hull must also accommodate a larger number of personnel on board (e.g. 165 persons) than for a dedicated LNGC. In order to lower operational costs, the hull designer must address specific requirements such as the access for offshore inspection of hull compartments and tanks, fatigue performance, corrosion protection systems, etc. Planning based on previous FPSO designs can yield a 40 year design life and reduced operational costs, with additional investment in the capital cost of the hull.

Although mooring systems seem to be simplistic in nature, the design and installation of a mooring system is crucial to the successful operation of an FPSO. For challenging locations (ultra deep water, severe ocean conditions), it can become difficult to even support the weight of the mooring lines. In some instances, dynamic positioning may be required in order to assure the station keeping of the hull during operation.
FLNG concepts have the option to consider an internal (through deck) or external (bow mounted) turret. The turret allows the connection of a rotating body (the FLNG) to a stationary system (risers and mooring system). In an extreme emergency, the turret also allows for the disconnection of the FPSO for an extreme weather event (e.g. a cyclone). The size of the turret is a function of the water depth and the amount of risers that interface with the topsides facility. It is a false perception that a turret and mooring system can simply become larger based on higher loads and deeper water. As these systems become larger, it becomes difficult to support the static weight of the components.

The Role of Safety

One of the impending unknowns for FLNG is the effect of process and operational safety on the design of the facility. At an absolute minimum, FLNG must carry the safety principles, philosophies, and practices developed from the FPSO industry. In order to advance FLNG to fruition, safety cannot be compromised by prototype designs, poor analysis, cost cutting initiatives, lack of operational experience, or the ignorance of the true risks of LNG production offshore.

Safety is a sensitive subject for FLNG, because there are not any existing LNG production vessels offshore. Safety will impact the application of liquefaction process technologies, the handling of refrigerants, the development of piping and equipment layouts, all of which drive the topsides facilities. Similar to FPSOs, there isn’t a definitive set of rules or criteria that can be applied to deem a facility is safe. As a result, the project has to demonstrate all reasonable measures have been taken to eliminate safety risks and that the residual risks are at levels acceptable to interested parties. The interested parties would typically include bodies such as the asset owner and operator, the financier, the operational jurisdiction, and possibly a Classification Society.

Hazard identification (HAZID) programs and a quantified risk assessment (QRA) are familiar means of identifying and quantifying risks. The HAZID is appropriate not only for FLNG in general, but for the analysis of less-familiar liquefaction technologies that are not used onshore. The QRA, by gauging the relative frequency of risks identified in HAZID, develops numerical comparisons in order to prioritize further engineering analysis. Some of the issues discussed during hazard identification include:

- Fire and thermal radiation
- Explosion and overpressure
- Vapor releases
- Structural integrity
- Collisions (via loading LNG or other)
- Equipment failures

In addition to client and contractor safety analysis workshops and procedures, the Classification Society will add a new layer of 3rd party review because no precedent has been set for LNG based offshore. Fortunately, Classification Societies such as ABS and DNV are developing rules for the design of floating LNG structures. It is uncertain as to the application of these initial rules toward actual projects in the development cycle, as even the most seasoned projects will challenge the new rules that have been written. Lastly, how can one estimate the net rework and redesign resulting from the HAZID, QRA, and Classification Society activities?

Another guiding principle of assessing process safety is the ALARP principle (as low as reasonably practicable) which has its origins in the UK. The basics of the ALARP principle are used to evaluate risks to determine where the additional cost to reduce a risk is balanced against the incremental benefit in risk reduction. When a given risk is between
catastrophic and inconsequential, the ALARP principle applies. Once engaged, a risk must be evaluated to determine the possible mitigation measures and the costs of implementation. On the surface, ALARP is simple in concept, but difficult in proof.

The ALARP principle holds such high importance in offshore design philosophy because it defines the process with which to evaluate risk while preventing exorbitant capital cost inflation. As a result, the ALARP principle can result in the following:

- The “design out” of unnecessary hazards
- Maximum allowable segregation of personnel to hazards / situations
- Multiple routes of escape and evacuation (temporary safe refuge – TSR)
- Formation of safe havens and temporary refuges
- Design mitigation measures for potential events
- The safe provision for personnel safety for 1 hour after incident identification

One of the interesting issues identified in this list is the concept of a temporary safe refuge (TSR) or safe haven. A TSR is not defined in a practice or standard, which can be copied from one installation to another. Statistically, the frequency of failure of the TSR is to be no more than $1 \times 10^{-3}$ per year \[11\]. The process of analyzing FLNG topsides to develop safe havens is a rigorous process that will result in rework of the topsides layout. Conceptual and pre-FEED projects that only focus on process technology selection and the basic layout of equipment and piping have not fully challenged the layout under the ALARP principle. Only the investment in a high quality FEED can mitigate the potential rework or cost escalation when performing a more thorough safety analysis.

It should be noted that the discussion of TSRs, safe havens, and reducing risks by ALARP doesn’t mean that the evacuation of personnel is a safe process either. Even the traditional transportation of personnel to the FPSO by helicopter is one of the greatest personnel risks on the project. The evacuation of personnel by lifeboat one hour after incident identification introduces an entirely new set of risks.

In the FPSO world, one thing is common: ALL FPSOs are different and all have been determined to be safe by rigorous analysis. As we look to the future of safety and FLNG:

- There is a disconnect between the drive to standardize and reality
- The first few FLNG projects will ALL be “first-of-a-kind” in regard to safety
- In 20 years, the FLNG map can be as diverse as the current FPSO map
- ALL FLNG VESSELS WILL BE SAFE – they must be

**Project Execution Issues**

In the mid 1990s, various business drivers such as the cost growth of jacket-based topside solutions, technical advances in subsea riser systems, and the shorter life of offshore fields resulted in an increased popularity of FPSO solutions. The FPSO became the industry innovation to make smaller and more remote offshore assets commercially viable. The initial perception of this innovation was that the FPSO solution was simple and easily fabricated because the solution was based the existing topsides designs of oil platforms. In many cases, FEED was limited to a quick concept definition to define equipment lists, generate layouts, and develop a factored cost estimate and schedule. Project cost and schedule was estimated based on shipping and fixed platform experience and cost and schedule validation was less of an issue because contractors were offering extensive production and schedule guarantees based on a lump sum turn key (LSTK) price.
This initial perception resulted in underestimating the technical complexity of an FPSO along with overly optimistic schedules. With the benefit of history, we should not be surprised by the large number of FPSO projects with delayed first oil and cost overruns. During execution, the technical complexity of integrating a standard tanker design with a standard topside design emerged quickly. Many changes were required to ensure the overall system would work and that the interfaces would match. Different regulations for shipping and topsides design further complicated integration. The two most common symptoms resulting in execution problems were the carry-over work from shipyard to topside/integration yard and weight growth of topside facility.

The issue of carry over work from the shipyard to the integration yard is mainly caused by the cultural difference between shipping and offshore design practices and regulations. Both industries and internal design practices have been very successful as standalone businesses. However, it was very difficult for engineers with different historical backgrounds to accept changes to each others’ successful designs. The list of technical issues is too long for the scope of this paper, but one simple mechanical example can illustrates this design challenge.

Ship designers are accustomed to installing mechanical couplings for piping on the basis that couplings are not sensitive to wave induced bending of the hull. However, an offshore culture is accustomed to welded piping systems on the premise that each non-welded connector is a potential hazard. The current consensus for FPSO design is a hybrid of these philosophies; the best solution is to base the piping design on welded systems with expansion loops that absorb the wave induced hull deflection. Unfortunately, solving such unexpected technical challenges has an effect on the budget and schedule.

Failure to manage growth in topsides weight is caused by underestimating the impact of the interface and integration issues that separate an FPSO design from a fixed platform. As expected, the difficulties in managing growth of the topsides weight are compounded when these issues are not fully developed in FEED. The offshore industry was used to familiar metrics to validate cost and schedule estimates, but it was difficult to verify if these norms would be applicable for integrated FPSO topside modules. As a result, some projects were hindered by “You don’t know what you don’t know.”

The engineering teams for FLNG will be facing similar first of a kind challenges and are susceptible to learning lessons the hard way – by executing the first few FLNG projects to see if these projects can be commercially successful for all stakeholders. Through conceptual studies and pre-FEEDs, it is evident that LNG and offshore regulations and design practices are quite different; establishing consensus on a set of merged FLNG design practices will take time and effort. The FEED for the first few FLNG facilities requires focused attention on identifying and mitigating technical and execution risk to minimize the inevitable changes during project execution. All projects have a unique evolution from conceptual design to operation, but technical or commercial show-stoppers could prevent the development of this new gas monetization business.

One potential execution challenge is the detail design of the new “compact” liquefaction train. The train boundary, which is smaller than for onshore LNG, will have the unique challenge of dealing with large bore cryogenic pipe on a flexible hull which could cause unique piping mechanical challenges. Although this issue can be overcome, the resolution must occur during a high quality FEED in order to mitigate unwanted changes during project execution. Since FLNG will have larger machinery, vessels, and piping than oil and gas FPSOs, the solutions are not obvious based on previous experience.

An FLNG project execution team must have a strong focus on identification, planning, and solving the physical and technical interface issues between the hull and topsides, because the interfaces will be different than for current FPSOs. Simply, the topside
weight of FLNG is equivalent to that of a large FPSO. The larger topside weights would also justify that the technical definition of the facility during FEED is sufficiently advanced to ensure the accuracy of cost and schedule estimating. Currently, there is a cultural difference between the methods used to generate the input for cost estimates for onshore LNG projects and offshore facilities.

General practice for offshore projects is to model piping to ‘shape approve’ all stress and interface critical lines. This approach enables over 70% of the piping bulk’s weight to be extracted directly from the 3D model. This result provides the confidence that the overall bulk weight estimate takes into account the impact of space constraints imposed by the limited plot size available.

These differences in methodology could lead to discussion about the level of engineering detail required during an FLNG FEED. For example, there may be a perception that the workhours required to complete the FEED and cost estimate based on the offshore approach is too conservative. However, if this perception is combined with pressure to minimize project cost prior to FID, predictable project execution could be at risk and estimates will require corresponding levels of contingency.

For a ‘first of a kind’ project, there is very little historical data with which to benchmark the weight and cost estimates for the FLNG topsides. The ability to benchmark estimates against historical data from recent similar projects provides further means of providing confidence in the forecasted cost and schedules for FLNG. The lack of directly relevant benchmark data, against which the project forecasts can be compared, surely makes the argument that a high quality FEED is necessary; deriving representative estimate input data is even more compelling than having reliable benchmarks.

Several project teams have started the journey of learning and solving these challenges, but this journey will be longer than commonly advertised. Studies based on existing LNG know-how or generic field-based solutions will form the building blocks of the future FLNG design manual, but they cannot prepare capable contractors and shipbuilders to accurately estimate the first FLNG. However, actual projects based on specific locations and gas compositions will enable innovative developers to implement FLNG. Additionally, it will take unique owner/operator companies to recognize the challenges and risks, engage the best designers and shipbuilders, and create the culture to encourage execution success.

**Interface Management**

Interface methodology and management is required for projects where multiple contractors are responsible for interconnecting scopes of work on a larger integrated project. In fact, interface methodology is not exclusively an offshore program; interface management is critically important for onshore “mega-projects” where many contractors may design and supply entire process plants along with a PMC or project management contractor. For FPSOs and FLNG, interface management is required between the hull and topsides contractors.

The scope of a proper interface program is beyond the scope of this paper, but the importance lies in managing a great deal of information, where each interface is critical to avoid workhour escalation or schedule creep. Implementing a successful interface program requires establishing a single point of contact in each contractor office for interface management. The singular contact will facilitate communication among contractors, document decisions, and resolve potential conflicts. In an EPCm contracting model (Engineering, Procurement, and Construction Management in one contract with FLNG Hull and Topsides construction by others), the overall administration of interfaces is performed by the EPCm contractor with support from the client.
The EPCm contractor will provide an interface management tool to control the status and flow of information regarding all interfaces. A robust tool provides the contractors with a structured method to manage the interfaces while allowing each contractor to efficiently communicate with one another. The functionality of this tool includes: the identification of responsibilities, status of interfaces, need dates for data, record of interface documentation, identification of overdue tasks, and progress measurement of the interface management scope of work.

For the first FLNG projects, it is suggested to deploy an interface management team from the EPCm contractor to the hull fabrication contractor to ensure the proper coordination of space management between the hull and topsides. This team would keep an overview of this critical interface and facilitate meetings to resolve potential clashes.

In addition to an interface management team, it is recommended to implement a system integrity program. This program would appoint technical “system owners” for each major system on the FPSO who have the responsibility for the overall design. The system owners would organize reviews with specific focus on the interface design to verify that the overall system will function in accordance with the project specifications. This team would provide technical assurance that can prevent late changes during execution, affecting schedule and budget.

**Other Issues, Data, and Metrics**

The experience gained through conceptual and pre-FEED FLNG studies provides a valuable head start in accumulating data while providing an opportunity to develop new metrics and procedures. However, FLNG FEED projects will challenge familiar LNG and offshore metrics resulting in a new set of design issues, best practices and metrics. Some of these issues include:

- Space efficiency
- Hull conversions
- Topsides weight estimates
- Piping weight estimates
- Workhour estimates

The efficient use of deck space is related to project cost. Additional space between equipment and modules is inherently safer, but at a high cost for plot area (empty space = $$). The initial equipment layout assumptions made during pre-FEED will be challenged in FEED when analyzed for constructability, safety, maintainability, and operability. Revisions made during FEED may impact both the topsides cost and schedule. Lessons learned from offshore LPG projects (e.g. Belanak and Sanha) as well as modular onshore LNG projects (e.g. Snøhvit LNG and Woodside Train V) will help to ensure a workable plot layout.

In April 2008, 60% of the FPSOs operating or on order were based on converted hulls. Although there are many successful FPSO projects based on converted tankers and hulls, the magnitude of topsides processing required for FLNG demands full attention to the integration of the topsides with the hull. As a result, it is not envisioned that the first FLNG projects would be based on existing hulls, with potential design unknowns, and previous operational wear and tear.

The execution and fabrication schedules for FPSOs are advertised to be as short as 24-30 months, but these schedules are based on well developed technologies and within known manufacturing limitations. As FLNG pushes the limits of topsides processing
capability on traditional hull shapes, it is imperative to develop a realistic schedule that
captures the design and interface issues among multiple contractors and fabricators.
The increased demand on module fabrication yards for other offshore projects (and
including modularized onshore LNG) may require interfacing with multiple fabrication
yards in order to complete the topsides in a suitable timeframe.

The potential growth of topsides weight is a significant challenge for large scale FPSOs.
If FLNG contains 50,000t or more of topsides, then a 10% escalation or error in the
weight estimate is a substantial deviation that may be impossible to overcome.
Comparing the potential weight escalation to the weights from Table 2 will highlight the
difference between oil and gas FPSOs and FLNG.

Offshore workhour metrics may apply to a large proportion of FLNG (workhours, steel,
schedules, etc), but what about details such as large bore LNG piping? There are no
offshore benchmarks for LNG piping. An offshore metric for module weight is that the
topsides weight is approximately four times the equipment weight. How will the large
bore piping affect these metrics? Another offshore metric is that approximately 16% of
the topsides weight is piping. This factor is perceived to be higher for large diameter
piping systems.

Workhour estimates for FLNG will be initially based on offshore metrics, but must be
adjusted for the technical complexity of LNG systems and the potential design
unknowns. It is envisioned that the high quality FEED workhours and the integration
workhours for large scale FLNG could be 3-4 times that of mid to large scale FPSOs.
Although these workhours may seem high based on FPSO metrics, it is clear that the
proper investment in FEED will result in design and execution certainty after FID.

Allowances for final integration at the site location (for subsea systems) and workhours
for final commissioning and startup are additional areas that require additional
development during FEED. As the subsea systems become larger and vessels move to
deeper water, the impact to the overall schedule is an area for future study.

**Conclusion**

The history of offshore engineering (not just FPSOs) is based on combining successful
leadership, technical experience, and individuals with a passion for offshore projects.
These projects require superior technical and execution competence due to the risks
placed on personnel operating in a restrictive environment. For FLNG projects, the
integration of an FPSO culture and LNG design and operational experience is necessary
in order to repeat the successes of offshore projects while not reliving the hardships. So
many technical and operational issues are new for FLNG that the client and contracting
execution teams should not be distracted by cost and schedule risks that could be
avoided by conducting a high value FEED.

There is no magic pill, potion, or formula for quickly and successfully implementing
FLNG. Mitigating risk is achieved with the sensible investment in a set of high quality
technologies, with a group of high quality contractors, who execute a high quality FEED
to deliver a high quality cost estimate. The challenge remains in identifying and
addressing “what you don’t know” during FEED to address these issues and interfaces
prior to the EPC or EPCm phase. This path to FID is essential to push FLNG to successful
fruition.

Issues will exist. Issues must be resolved, because designs will be challenged during
FEED. However, issues cannot be ignored during FEED or delayed to EPC to add risk to
contractors, shipbuilders, and owner/operators. A properly structured execution plan,
based on the history of FPSOs and complex LNG projects, will create a plan with a high probability of success.

The sufficient development of FLNG concepts (comparing suitable technologies, analyzing safety, and having a high confidence cost estimate) can lead to commercially successful projects that are completed on-time and within budget. We must learn from the technical and execution lessons of FPSOs in order to repeat the best practices and avoid the mistakes. History does not repeat itself, but it does rhyme.

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