Challenges and Risk Allocation in FSRU Projects.

Holger Kelle, Director INCITIAS, September 2015

Abstract

The paper explores why only just around half of all intended FSRU and nearshore regasification projects are progressed beyond concept stage. The paper explores what obstacles, challenges and risks FSRU and nearshore projects face. And the roles technology, investors, lenders, operators, shipping companies and LNG suppliers, pipeline operators and energy policy plays in the establishment of nearshore regasification terminals.

Motivation

The Author has worked since 2005 on over 30 of the world’s FSRU and nearshore terminals (re-gas on jetty or onshore with LNG FSU) mostly from concept to pre-FEED and FEED design to EPC contracting. This equals to around 50% of the world’s FSRU and nearshore projects that have been planned, committed, completed and cancelled since 2005. Out of the 30 projects 38% are completed or committed (EPC/Lease contract signed) with further 17% being in planning stage beyond concept selection. The remaining 45% are shelved or cancelled. The high rate of early resignation of these projects has led the Author to review the past projects for mayor risk and challenges that have created obstacles of these projects. The aim is to explore if there are lessons to be learned and to identify the common challenges.

Background

The context of rising global energy demand, and the need to diversify the fuel mix to better compensate for fluctuations in the market in highly populated areas where space for shore facilities is scarce has led to the steady rise of floating regasification developments since 2005. Currently there are more than 16 terminals in operation or about to be commissioned and further 14 have been taken to the EPC bidding stage or are in detail design or under construction. A further 21 terminals are in the planning phase. Out of these 5 FSRU terminals have already been decommissioned or mothballed.

Since 2009 we have seen permutations of the traditional FSRU that resulted in jetty and shore based regasification with floating storage units (FSU).

In the beginning the majority of terminals were designed for seasonal demand, however overtime FSRUs have proven to be robust and able to deliver base load (continuous) regasification.

The floating storages regasification terminals all receive Liquefied Natural Gas (LNG) at ambient pressure and at cryogenic temperatures of around -160ºC. The FSRU stores the LNG and then regasifies the LNG usually by heating it to around 3ºC to 7ºC and pressurising it to natural gas pipeline pressures which can range from 40 barg to above 100 barg.

The nominal storage volume of LNG on board a full scale FSRU/FSU ranges between 120,000m³ to 266,000m³ and utilises standard LNG Carrier hulls as a base ship. LNG FSRU/FSU terminals usually have a mooring system that is suitable to moor the large LNG Carrier either permanently or temporarily within prescribed limits of the required gas availability per annum and the achievable environmental limits of the mooring. The high pressure gas is then either transferred from the FSRU to shore via a (subsea) pipeline or LNG is transferred to a regas unit mounted on an offshore platform (most commonly on the FSU jetty) or to a regasification plant onshore. High Pressure gas from the offshore facility is transferred via a subsea pipeline to an Onshore Receiving facility, and this is often where gas metering, or further gas heating and conditioning takes place, and the tie-in into existing gas networks is controlled.

The re-gas capacity for full scale FSRU and FSU application ranges between 0.5 and 6.5MTPA with majority of facilities operating around the 1.2-3.0MTPA range (H.Kelle, 2014).

Small Scale regasification is on the rise and more than 25 units are expected to be realised by 2020 in South East Asia alone. These facilities range from micro facilities of less than 0.1MTPA to just under 0.5MTPA and are likely to be used to service insular markets and power generation facilities of up to 300MW. The storage of small regasification systems can vary greatly such as the use of small scale LNGCs with LNG storage capacity of 8000m³ to 15000m³. A key benefit of small storage vessels is...
that they can significantly reduce capital expenditure due to smaller infrastructure requirements and lesser draught requirements, compared to the full scale version which have to be placed in deeper water and therefore often further offshore.

Floating Storage Regasification Terminals Success factors.
The success of Floating Storage Regasification Terminals in the past was and still is driven by the availability of proven technology.

Further a key success factor for FSRU and nearshore re-gas projects is the possibility to fast track projects by utilising existing LNGCs for conversion to an FSRU or FSU or the use of an off-hire FSRU.

“Ease of Finance and Contracting”

The FSRU and FSU market has accelerated since project developers were able to attain lease options for FSRU/FSU as the enable a reduction of capital expenditure. In addition FSRU and FSU lease operators benefit from cheaper shipping finance since most FSRUs are considered LNG Carriers that can operate as ships in an LNG supply chain and hence are re-deployable.

The ability to lease close to 50%-80% of the total investment cost, leaves the more difficult non-recourse financing (project financing) to minimal fixed infrastructure such as mooring, pipelines and Onshore receiving facilities (ORFs). The relative simplicity in which an FSRU can be hired using standard shipping lease contracts and the relatively small onshore footprint have made these types of terminals attractive for emerging economies.

Risk Allocation
The following sections explore the various risks that need to be considered to successfully deliver floating regas terminals.

Market Risk
The downstream market risk can be summarized as follows:

- Lack of Market Demand
- Competing Fuels
- Downstream Buyer Credit Risk
- Natural Gas Pricing
- Regulatory / Legal Regime

The Upstream Supply Risk are:

- Insufficient Reserves

- Failure of Supply

Within the gas industry, the LNG business requires a comparatively enormous investment in infrastructure which necessitates rigid contractual relationships throughout the LNG value chain. Due to these complexities it misleading and to speak of a global LNG market, as the industry is more an accumulation of contractual monopolies. Efforts are currently underway to commoditise LNG and to create LNG Hubs in Asia, which is likely to create a significant change how LNG is contracted in the future.

Figure 1 LNG VALUE CHAIN

The main current reference points concerning gas prices are the Henry Hub (HH) price in the United States, the NBP in the United Kingdom, and the average Japanese LNG import price. While these are important benchmarks, they fail to reflect the diversity of gas prices, notably in terms of levels and geographical coverage.

The standard pricing references are relevant for developed countries, but not always for developing ones.

In the IEA report “The Asian Quest for LNG in a Globalising Market 2014”, Anne-Sophie CORBEAU (et al) reports “Gas prices are determined according to different gas pricing mechanisms. Since 2005, the International Gas Union (IGU) has been reviewing the evolution of gas price levels and has pricing mechanisms across the world in its wholesale gas pricing survey. The eight different gas pricing mechanisms are outlined in Table 1.

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil escalation</td>
<td>The gas price is linked to oil or oil products</td>
</tr>
<tr>
<td>Gas-to-gas</td>
<td>The gas price is determined based on supply/demand fundamentals</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bilateral mechanisms</td>
<td>The price of natural gas is agreed upon between two governments for a certain duration</td>
</tr>
<tr>
<td>Netback price</td>
<td>The natural gas price is linked to the end product; this happens sometimes in the case of methanol</td>
</tr>
<tr>
<td>Regulation cost of service</td>
<td>The level of the gas price covers the costs of production and transport plus a certain margin</td>
</tr>
<tr>
<td>Regulation social and political</td>
<td>The gas price is decided on an ad-hoc basis by the relevant ministry</td>
</tr>
<tr>
<td>Regulation below cost</td>
<td>In other terms, the gas price is subsidised</td>
</tr>
<tr>
<td>No price</td>
<td>The gas is given for free; this tends to disappear</td>
</tr>
</tbody>
</table>

Table 1 (IGU (2014), Wholesale Gas Price Survey, 2014)

The IGU study highlights two very important facts. Looking at the pricing mechanism at the wholesale level, it is striking that gas-to-gas competition represents around 43% of the gas sold globally, twice as much as oil-indexed gas which represents only less than 20%. Also of note is the important share of the different types of regulated gas prices, which together represent 33%", (The Asian Quest for LNG in a Globalising Market, NOV 2014).

Further the IGU report states that more than 71% of LNG imports are priced based on oil indexation, while for pipeline gas this reduces to 48%.

Oil indexation has existed for several decades and long been the unchallenged pricing mechanism governing imports and sometimes gas production. The mechanism was first adopted in the 1960s when the Netherlands was looking at exporting part of its natural gas production from the Groningen field, which was discovered in 1959 and started producing in 1964, the underlying aim of oil indexation is to establish pricing on a “market value principle”.

Typically, an oil-index pricing formula looks as follows (IFRI, 2011):

\[
P_m = P_o + 0.60 \times 0.80 \times 0.0078 \times (LFO_m - LFO_o) + 0.40 \times 0.90 \times 0.0076 \times (HFO_m - HFO_o) + K
\]

In this formula, \(P_m\) represents the gas price in month \(m\). \(P_o\) is the reference gas price, while \(LFO_o\) and \(HFO_o\) are the reference prices of light fuel oil and heavy fuel oil. \(LFO_m\) and \(HFO_m\) represent the prices for the month \(m\), but actually are usually the averages of the previous six to nine months with a time lag of one to six months. The coefficients 0.60 and 0.40 represent the shares of the market segments competing respectively with light fuel oil and heavy fuel oil. The coefficients 0.80 and 0.90 are pass-through factors. \(K\) is a fixed factor.

In 2012 the IEA predicted the LNG demand to double in South East Asia between 2010 and 2017 as shown in Figure 3.

At the time of writing (Sept. 2015) the WTI was at its lowest in 5 years ($37.75/bbl) causing significant downward pressure on the LNG price, it appears that when in 2013/2014 the WTI prices were consistently above the US$100/bbl mark and Japan shut down their nuclear power plants that this created a rush to buy LNG. Now some LNG buyers have over-contracted, and are likely to dispense of leftovers in the LNG spot market.

For example in early September 2015, CNOOC issued a tender to sell two October-November cargoes from the 8.5MTPA Queensland Curtis LNG...
As reported by ARGUS: “Market participants said CNOOC was also looking to sell more QCLNG cargoes over the next three years, indicating that it has more LNG supply than it needs…Sinopac has contracted to buy 7.4MTPA from the 9MTPA Australia Pacific LNG (APLNG) plant, which is expected to start up by October 2015 but Sinopac is not expected to absorb all its contracted volumes as it faces construction delays at two new 3MTPA import terminals.” (Wan, 2015). This example highlights the importance that accurate demand forecasting and project schedule certainty is a key factor in the current market environment which has low spot market prices and significant pressures on gas due to competitive oil pricing.

Interestingly, the LNG production capacity and delivery infrastructure in existence today corresponds almost exactly to global LNG contractual demand. Excess capacity tends to exist only on a temporary basis linked to timing differences in the construction of dedicated supply and demand infrastructure. Although we have seen an increase in spot and short-term market cargoes to around 35% of the global LNG market. It needs be understood that the majority of these cargoes were delivered within the existing logistic chain and that the spot market bidding process was used to establish the spot/short-term cargo prices outside the already contractually committed volumes. Some industry players observed that less than half of the spot/short-term cargo was actually available to off-takes outside the established logistic chains.

Figure 4 indicates the current trend of spot pricing vs oil pricing. Trends on the graph indicate that for LNG to remain competitive in spot market environment the regasification cost needs to be significantly lower than $2/mmBTU and more likely less than $1/mmBTU to remain competitive in changing markets.

In contrast to the current underlying difficulty in competitive gas pricing in comparison to oil, the long-term trends for gas demand still indicate growth of 1.5% per annum worldwide and 2.8% per annum (almost double!) for South East Asia. This trend is shown in IEA’s demand forecast (Figure 5). These trends suggest that the current glut in the market is likely to be absorbed within the next 12 to 18 month, significant pressure exist on the LNG industry from shale gas developments and renewable energy. (Tighe Noonan, 2001)

Shale gas production growth and renewable energy depend greatly on policies and the associated sovereign risk LNG developers face from policy uncertainty and remains one of the key risk issues to be considered for long-term project viability (Figure 6 & Figure 7).
### ASEAN Electricity generation by Source

<table>
<thead>
<tr>
<th>Source</th>
<th>2011</th>
<th>2035</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fossil fuels</td>
<td>86%</td>
<td>78%</td>
</tr>
<tr>
<td>Coal</td>
<td>31%</td>
<td>49%</td>
</tr>
<tr>
<td>Gas</td>
<td>44%</td>
<td>28%</td>
</tr>
<tr>
<td>Oil</td>
<td>10%</td>
<td>2%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>0%</td>
<td>2%</td>
</tr>
<tr>
<td>Renewables</td>
<td>14%</td>
<td>20%</td>
</tr>
<tr>
<td>Hydro</td>
<td>10%</td>
<td>11%</td>
</tr>
<tr>
<td>Geothermal</td>
<td>3%</td>
<td>3%</td>
</tr>
<tr>
<td>Bioenergy</td>
<td>1%</td>
<td>3%</td>
</tr>
<tr>
<td>Other</td>
<td>0%</td>
<td>3%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>100%</td>
<td>100%</td>
</tr>
</tbody>
</table>

*Figure 6 ASEAN electricity generation by source (IEA 2013)*

### Markets (Microeconomics)

The challenges that effect individual terminal economics are associated with:

- Terminal flexibility.
- Terminal availability.
- Economic viability.

At the individual terminal level the economic viability is driven by the types of markets the terminal serves and there are generally two distinct types of markets:

- **Seasonal load markets**, typically located in the northern hemisphere (Europe and North America).
- **Base load markets**, typical of equatorial countries.

In seasonal load markets, the regasification terminals are generally designed to provide gas during periods where there is an increase in energy demand as a result of seasonal changes, such as the increased energy demand for heating during colder seasons. In these markets, gas is generally provided by a main supply source (such as gas via pipelines), with the floating regasification terminal providing the supplemental gas supply to cater for peaks in the seasonal demand. In contrast to seasonal load markets, gas demand in base load markets is characterised by a constant base loading with routine daily fluctuations as a result of human activities.

It is further expected that as the local economy grows, the base loading would grow in parallel with the economy in order to satisfy its energy demands.

With floating regasification terminals typically having a 20 - 30 year life cycle, a 10% annual power demand increase would mean a doubling of power demand approximately every seven to eight years.

In practice this could mean that the regasification capacity needs to increase from a nominal 1.5 MTPA of LNG during the initial years of operation, to 3.5 MTPA over a 20 year life cycle.

The design of base load regasification terminals therefore needs to consider not only the potential doubling of regasification capacity, and to cater for this change in demand in an economically prudent way, but also needs to meet the daily demand fluctuations by having the ability to ramp-up and ramp-down gas production, caused by the power plant duty cycles and the lack of a wider natural gas grid smoothing the sharp peaks in the demand curve. Long-term commitment and market instability require the lowest possible cost for regasification.
The graph below shows the typical levelised cost of energy (LCOE) per mmBTU for a typical FSRU regas terminal and small scale solution at the lower throughput end utilising small scale LNGC and minimum infrastructure facilities. Generally the leasing of FSRUs provide 20-30% better LCOE’s especially for short term projects (7-15 years) partly because the underlying FSRU lease rate is commonly more in line with shipping time charter leases that use a longer finance and higher residual values at the end of lease than fully amortised at end of lease non-recourse finance projects. The graph (Figure 8) below depicts typical LCOEs (50% probability accuracy, i.e. equal chance of over-run or under-run) that can be achieved by full scale floating storage terminals and small scale re-gas terminals. The LCOE below considers lease of the FSRU/FSU a 10% equity in infrastructure with 90% finance of infrastructure.

**Figure 8 LCOE vs Throughput for floating regas terminals**

The graph clearly shows that the curve flattens at 1.0 to 1.25 MTPA and that to be able achieve tolling tariffs of less than $1.50/mmBTU the terminal needs to operate a throughput of more 1.2 MTPA. For small scale regas terminals, even with their minimal infrastructure it will be extremely difficult to achieve tariffs of less than $1.50/mm BTU. The economic viability of the regasification terminal needs not only to consider capital expenses (CAPEX) and operating expenses (OPEX), but the life cycle costs associated with sourcing and delivery of LNG to the regasification terminal. These are necessary in order to ensure that supply of LNG maintains a high availability and to ensure that the increasing base load demands are met.

Evaluation of the life cycle cost can be carried out in two stages. The first stage is to identify LNG supply terminals that would provide gas matching the specification requirements of the local power plants and terminals that would provide the required volume of LNG to meet the gas demand. Gas specifications would include gas molecular composition and heat values. Where the gas specifications do not match the requirements of the power plants, additional process equipment could be added to the regasification terminal or the power plants to ensure compatibility, although this would be at an additional cost. Having identified suitable LNG supply terminals, the next stage is to manage the logistics of delivering LNG to the regasification terminal. To achieve an optimised logistics chain, a large number of factors need to be considered, including the size and type of LNG carriers, storage capacity of the regasification terminal, route selection and so on. This would typically entail a large number of scenarios to be considered during the initial planning stages, in order to fully understand and identify the key drivers of the life cycle costs.

**Terminal flexibility**

Designing for terminal flexibility addresses the challenge of keeping up with annual base load demand growth, as well as the routine daily demand fluctuations. Catering for future base load demands during the design of floating regasification terminals is not only capital intensive, it is also operationally inefficient as the regasification equipment is operated below capacity (at least during the initial years of operation), not to mention the higher maintenance expense that will be incurred in the meantime. To provide an economically attractive solution and to cater for the increased demand, a flexible design that allows the terminal regasification capacity to be staggered is required. This not only provides savings during the initial capital works, but the flexible design allows the terminal to keep up with actual market demands (as opposed to projected market demands).

To design for daily demand fluctuations, detailed knowledge of the nature of fluctuations is required. This allows correct sizing of key regasification components (such as pumps and vaporisers) and the development of operational philosophies to provide ramp-up and ramp-down capability.

**Terminal availability**

Terminal availability is a measure of the time where the terminal is online and supplying gas to the onshore power plants/gas distribution grid. Availability is commonly expressed as a percentage on an annual basis. For example, a terminal with 98% availability annually will mean that the terminal is supplying gas approximately 358 days of the year. For base load regasification terminals, high
availability is driven by market demands and is a strict requirement (generally above 98%). This high availability means that the terminal either has to be permanently moored or the facility has to utilise two regasification vessels that can be alternated; the latter solution would incur significantly higher capital expenditure and operational cost. In contrast, the availability for seasonal load markets would only have to be 40 - 60% annually (market dependent) to satisfy the seasonal demands and for these markets a permanently moored facility is therefore not required.

The requirement of a permanently moored terminal means that it is not possible to remove the facility for lengthy service periods in a dock/shipyard. This necessitates careful consideration during the design process, especially in the design of the regasification (process) equipment and LNG storage tanks. The challenges in designing regasification equipment lie in the marinisation process (adapting land based regasification technology for the offshore environment) and in ensuring high availability of the equipment. Both of these challenges can be addressed by a design centred on minimising downtime (via designing for operational flexibility that allows continuous operation during partial equipment failure) and minimising maintenance/repair operations offshore. Another challenge is the selection of the appropriate LNG cargo storage system. The challenges associated with LNG storage tanks are not only sloshing related, but also relate to the maintainability/routine inspection of the storage tanks without bringing the facility into a dock/shipyard (H. Kelle, 2014).

### Financing Risk of Floating regas terminals

The financing risk can be summarized as:

- **The Credit & Payment Risk:**
  - Risk of Non-Payment
  - LNG or Gas Offtaker Creditworthiness
  - Charterer Creditworthiness

- **Liquidity Risk:**
  - Cost-overruns
  - Invoice and cash-flow mismatches
  - Commissioning and ramp-up periods

- **Force Majeure:**
  - “Unforeseeable” risk
  - Acts of God

- Inter-dependency of force majeure clauses throughout LNG Supply Chain
- Force Majeure Clauses frequently not back-to-back
- Role of State in Supply, Transportation and Offtake

In contrast to investments backed by state-to-state agreements among high investment grade major oil companies and equivalent rated utilities, new LNG Floating storage regas terminals investments rely on below investment grade entities to ensure sufficient long-term revenues to support a multi-million dollar investment chain, i.e. non-recourse or limited - recourse financing. The non-recourse or limited recourse finance is backed by the contracted cash flow of the asset. Hence, the lender will look in great detail at:

- Project specific asset
- Strength of the Charter contract
- Strength of Charter counterparty
- The longest tenor financing possible

The financing tenor of the assets are usually limited to the contractual time limits. The need for strong EPC and charter contractors with strong balance sheet make it necessary to find the right partners to ensure project success. Apart from the project specific assets design, construction and management, the focus when selecting partners is on market liquidity, balance sheets and strong contractual cash flow.

From a lenders point of few the following due diligence areas will be focused upon:

- Liquidity
- Balance sheet strength
- cash flow
- Technical robustness
- Legal structures and framework
- Insurance, and
- The Tax/ commercialisation Model

The issues are compounded by the approach being taken towards the financing of the different in-country components of the chain; the LNG port / import terminal / regas and storage (FSU) on the one hand and the distribution network and power plants on the other hand, with the emphasis being placed on the private sector, IPPs and Clean Energy Development.

Due to this complexity none of the players in an LNG-related activity will fully launch an investment in a component piece or disburse significant funds until it has received formal confirmation that every other actor involved is equally committed.
What often becomes a problem in many developing countries is the need for a strong regulatory framework. Many projects fail due to complex contractual matters and the inability to limit project risk allocated to the terminal company as well as a lack of well-defined project risk allocation and control methodologies. Because of this there is a preference in the gas off taker industry for tolling models. The tolling model transfers some of the LNG import business risks, such as supply and market risk, on foreign or third parties.

As explained in (Tighe Noonan, 2001) the term “tolling facility” implies a unit for which the user pays a fee remunerating the services provided. The arrangement illustrated in Figure 9 is one where the terminal infrastructure is built and financed by a special purpose entity that contracts out its services to the user, which is either the seller of the LNG or the purchaser of regasified gas, in exchange for a fee. The fee represents the entity’s only source of cash flow and covers operating expenses, debt service (interest and principal amortisation), taxes and shareholders’ return.

The risk to which a tolling-based terminal project is exposed, other than its intrinsic operating risks, will typically be limited to the creditworthiness of the fee-payer. Specifically, the tolling unit is not exposed to the margin risk between buying and selling LNG.

Another aspect is the commercial balance, the tolling unit may be subject to certain volume fluctuations reflecting the volume variation provisions of the SPA itself. To deal with this risk, a tolling unit will typically be remunerated through the combination of a capacity fee and a usage fee. The capacity payment will be sized to cover non-variable operating costs, minimum debt service obligations and the base return for equity and is paid whatever the level of usage to reflect the tolling unit’s obligation to make the capacity available. The usage payment will cover variable operating expenditures, any debt service not met under the capacity payment regime, and the shareholders’ performance based-return.

An alternative is the merchant model but that would require the high investment grade major oil companies and equivalent rated utilities to take part in this.
Noonan and Martin (Tighe Noonan, 2001) explain further that the main characteristic of a merchant operation is that the terminal entity is the Signatory to the Supply Agreement (SPA) (see Figure 10) acting as both importer and marketer. While it may be supported by back-to-back offtake agreements, it sits contractually between LNG producer and gas user. Under this type of arrangement, it effectively pays for its own services through the margin achieved between cost of gas and the sales price into the local market.

**Legal Risk**
- Breach of contract and non-performance
- Enforceability
- Contractual ambiguity or silence
- Dispute resolution
- Insurance

The complexity of aligning the contracts and the necessary backing by lenders is one of the major hurdles floating storage regasification projects need to overcome. During the early phase of a project the project interdependencies and interfaces require a thorough understanding. Whether a project is able to go to the EPC bidding stage is mostly determined (apart from securing SPAs and SGAs) by enabling EPC contractors to form suitable alliances. The objective of all parties is to ensure that each risk is properly shouldered by the entity best able to bear it. This is commonly achieved through a combination of contracting, including liquidated damages and warranties, insurance, contingencies, due diligence and structure, including finance structure. However, determining the best combination is often challenging due to the inherent construction risks.

**Construction Risk**

A major difference between traditional onshore facilities and nearshore floating storage terminals is the challenge to the EPC contractor to manage onshore as well as offshore infrastructure. Here the project requires the experience from offshore oil & gas EPC contractors to manage and understand the installation and construction risk. While these contractors are important, they often lack onshore infrastructure competency to manage the various onshore interfaces, such as:
- Tie-in,
- right of way,
- Utilization of local labor,
- Electricity and utilities supply, and
- Worker camps and construction material storage areas.

Offshore Projects require astute marine and offshore contractors that understand the logistic challenges of a terminal construction 10 or 20km offshore demands. The EPC prime contractor will have to have an appreciation of offshore installation methods that minimize exposure to unfavorable weather windows and the number offshore workers exposed at any point in time.

**Operations Risk**

The problems of construction risks are compounded by a lack of operators with LNG experience and availability of re-gas process construction yards with cryogenic construction and commissioning experience.

The various interfaces, between suitable EPC alliances or Prime contractor with sub-contractor relationships, compounds typical construction risk such as:
- Delays in construction
- Cost-Overruns
- Performance below guaranteed parameters
- Materials and Labour Cost and Availability

As highlighted above the key operational risk in developing nearshore regasification terminals is the lack of operators that are not connected to major oil & gas or major utilities companies. This operational is in particular an issue in a build-own-operate-transfer contract model (BOOT) the prime contractor (EPC) has very limited access to independent operator experience. This is a legacy of the rigid LNG supply chain that traditionally included state owned or major oil & gas companies who in the past did not outsource terminal operations to third parties. This is issue is magnified for floating storage terminals with the regas facility on a jetty or onshore. FSRU terminals are somewhat simpler than the service and operational agreement is most often with the FSRU lease operator who will staff their FSRUs through traditional ship management companies. On the shore (high pressure natural gas) site the availability of suitable operators is greater and often readily available within country, since the experience of personnel required can be found within traditional natural gas infrastructure operators.

Operational risk issues come to the fore when EPC contractors try to qualify their PMC teams during the bidding stage or try to assemble suitable alliances. In addition to issues of operator performance, the availability of labourers, equipment failures of onshore equipment (now operated in a marine environment) may increase operational cost.
Political Risk

The political risk can be summarized as follows:

- Governmental support for project
- Permitting and Authorizations
- Role of State in Supply, Transportation and Offtake
- Developed vs. Developing Regulatory Environment

The long-term viability of a projects depend on strong political backing and regulatory environments that provide certainty for gas demand. In 2013, the IEA issued a report, *Developing a Natural Gas Trading Hub in Asia* (IEA, 2013c), which looked at what was necessary to develop a trading hub in Asia. The main lessons from the report are that a competitive market would be required in order for such a trading hub to be developed. This market would need to meet a set of institutional and structural requirements to create the confidence to attract new participants (namely, financial) and to encourage market players to use a trading hub for balancing their portfolios.

Among the first steps to complete this process would be unbundling of transport and commercial activities, and price deregulation at the wholesale level. As well as the establishment of pipeline access codes and regulators.

Once these conditions are met, sufficient network capacity and non-discriminatory access must be made available. *(The Asian Quest for LNG in a Globalising Market, NOV 2014).*

Past Projects Lessons to be learned

INCITIAS in-house data base has counted total 62 floating regasification terminals that were either Completed, Committed to go to EPC, Cancelled or In-Planning. The number of cancelled projects is 14

The main reason for the cancelation of the 14 projects was market risk, and in most instances demand was initially over projected or the project developer was unable to secure LNG supply.

This is followed by political risks, where projects either faced severe opposition from Politians and people who did not want such a project in their backyard or from lack of market access. In other words the lack of de-regulation and often lack of access to existing pipeline infrastructure. The latter was most frequently a hurdle in South East Asian Projects. Political stability is further reflected by the inability to secure suitable finance for the project.

For projects “in-planning”, in which INCITAS consultants were or are currently involved, the largest thread to successful implementation is the political risk.

There is an interrelation between political, market and financing risk, as without the political backing, and the lack of SPA and GSA there is no finance possibility. Projects that face construction and operations risks have commonly attracted sufficient interest by LNG suppliers, Government and Lenders to progress further.

The projects with the greatest success are projects that have some direct control over the gas demand, i.e. IPPs that have power plants with direct demand for the gas and established electricity distribution networks. Other successful IPPs include those that
are developing a power station and require some form of competitive fuel supply.

When state owned oil & gas and utilities are involved, gas demand forecasting is often inflated to achieve favourable sanctioning by reducing $/mmBTU threshold. These projects end-up relying heavily on government subsidies and this in turn is likely to dampen de-regulation of the gas market at a later stage.

Projects entirely driven by politics frequently set unrealistic schedules and over promise on the gas demand to attract interest by LNG suppliers and to appease voters.

Finally, only state backed or equity rich companies with balance sheets that can support a multibillion dollar supply agreement are currently in the position to develop full scale floating regasification terminals.

However, this is no longer the case on the small scale site, where there is now an emerging LNG hub market developing. The limited infrastructure cost required to set-up small scale LNG and readily available technology will continue to open the market to smaller players.

The combination of EPC and operation contracts in BOOT style tolling terminals have significant challenges to attract competent alliances. The Developing of tender packages for EPC and operational requirements requires understanding of the market’s response and the tender process needs to allow for sufficient time that these alliance by EPC contractors and operators can be formed.

The IPP contracting culture, with its limited engineering definition prior EPC and functional specification, creates significant problems when identifying the weakness of EPC tender responses and the attraction of interest by gas suppliers to even discuss the possibility of LNG supply.

References


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