WATSON FARLEY & WILLIAMS

THE ANATOMY OF AN LNG TO POWER PROJECT
THE RISK MATRIX MITIGATED

OCTOBER 2020

PUTTING LNG-TO-POWER INTO CONTEXT

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PUTTING LNG-TO-POWER INTO CONTEXT

As the world transitions to a net zero goal within the next 30 or so years, we think that LNG will be a key component in that transition. As indicated in the 2020 BP Statistical Review[1], while coal will remain a dominant energy source in the global energy mix, natural gas and LNG, especially if they can be blended with hydrogen and potentially (in the future) changed to synthetic gas produced from bio sources, are well placed to support this global transition to net zero, not least in power production.

In the last 10 to 15 years, the LNG sector has evolved from the traditional point-to-point LNG delivery system to a dynamic market with integrated components and new participants resulting in a deeper market. This change has largely been facilitated by the emergence of floating modular construction for liquefaction and regasification as well as power and desalination plants. In addition, a substantial increase in shipping and liquefaction capacity keeps increasing LNG market liquidity which, in turn, has allowed new sales models to be created by LNG aggregators and portfolio traders to change the availability of LNG globally. This has enabled them to adjust the global supply/demand profile by making a mixed portfolio of spot, short-, medium- and long-term supply options available to buyers. This portfolio mix has also been driven by, and itself keeps driving, different pricing models. Whilst traditional oil indexation remains strong, gas hub pricing linked to NBP, Henry Hub and TTF has emerged as well as spot pricing linked to indices such as JKM and various digital trading platforms such as GLX.

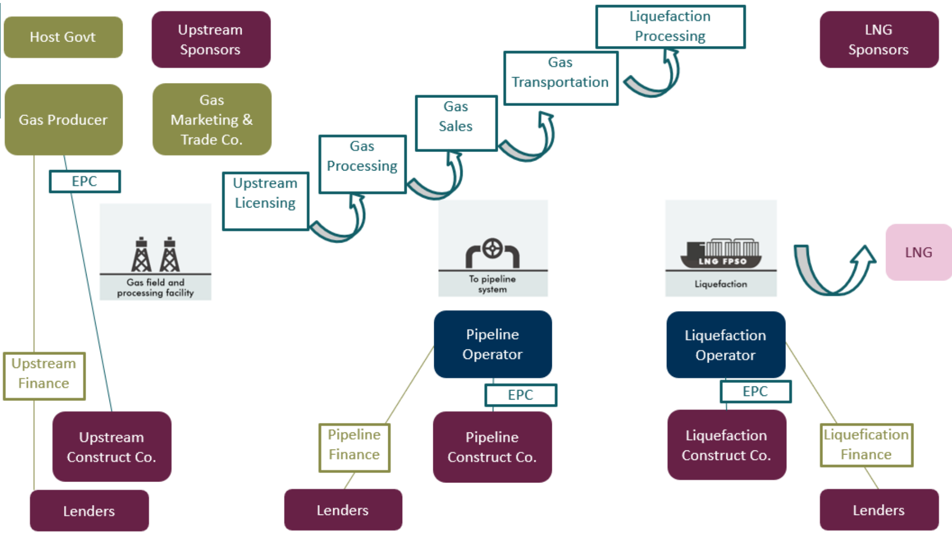
MULTIPLE PROJECTS

When we talk about LNG-to-Power, then we mainly focus on the last third of the LNG value chain, i.e. the supply to market (that is, effectively, the downstream portion of the LNG value chain). However, the overall LNG value chain comprises an ever-growing number of projects with a variety of sponsors, lenders, governments, contractors and other participants. Of course, the technology and market changes mentioned previously have enabled a different, more flexible LNG value chain to emerge from which LNG-to-Power projects benefit. With growing numbers of participants, complexity is likely to increase further and a clear understanding of the 'full picture' of the project-on-project risks that are created along the value chain, and those that will affect LNG-to-Power projects at the end of that chain, is paramount.

This article will focus on the downstream segment of the LNG value chain, however, we believe it pays to briefly consider risks further upstream that will affect the positive outcome of any LNG-to-Power project.

[1] https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2020-full-report.pdf

UPSTREAM



Obviously, before gas can be converted into LNG and later into electricity, it needs to be sourced, developed and produced. Looking, therefore, at the upstream component of the gas value chain first, by granting licences to exploration and production companies host governments traditionally pass the exploration and ultimately reservoir risk on to the upstream investor producers. The construction and financing of the upstream infrastructure, including wellheads and gas processing facilities, create an additional set of risks for these investors, all of which must be mitigated or passed through the value chain.

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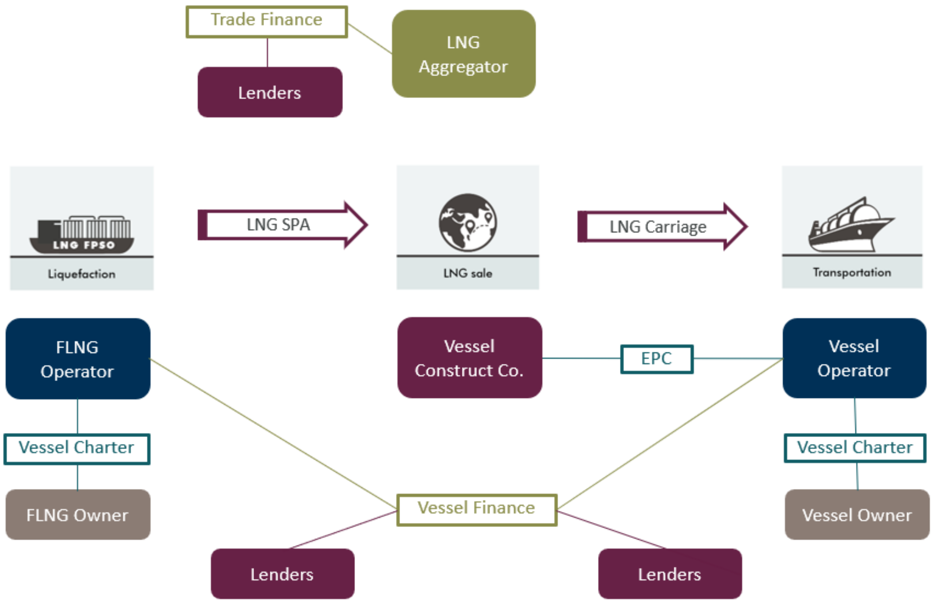
Assuming commercially exploitable gas reserves have been located, moving the hydrocarbons to market requires pipeline infrastructure, and gas sales arrangements and transportation agreements to be put in place. The techniques of splitting these risks between different participants first emerges in the overall value chain with producers selling to marketing companies, specialist pipeline companies moving the molecules and separate special purpose companies (SPVs) owning key infrastructure to ringfence the risks and allow for the use of limited recourse financing.

The significant costs involved in converting gas to liquid by liquefaction have gradually reduced in the last ten years or so through the use of floating modular construction. This has itself allowed access to reservoirs too small and often at locations too far offshore to support the development of traditional onshore liquefaction projects. While Prelude on the North West Shelf is one example, Novatek and Total's Arctic LNG 2 project looks to use floating technology in the form of nearshore gravity-based foundations and modular construction to deliver both the liquefaction terminals in the Arctic as well as two transhipment terminals at a cost that can be supported by the market.

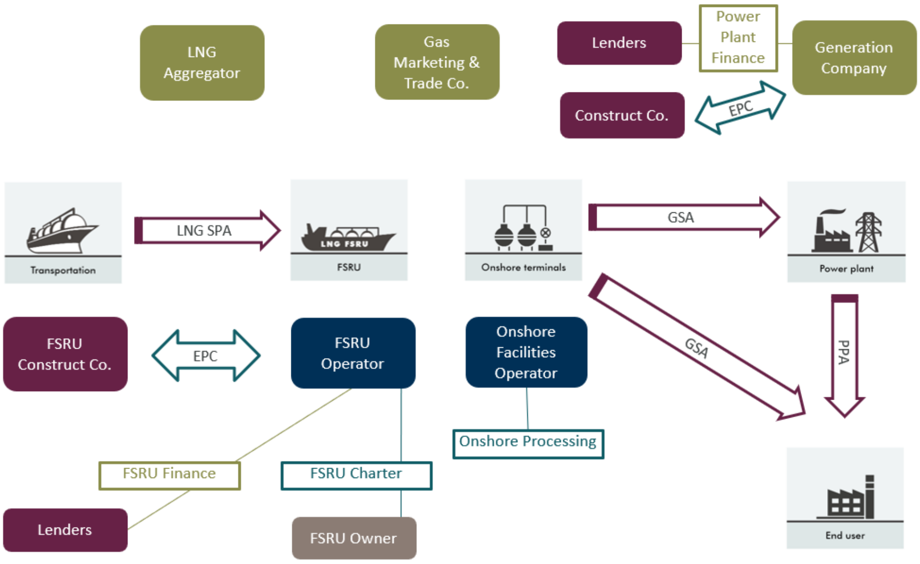
MIDSTREAM



"It is perhaps in the midstream part of the LNG value chain, that is, the sale and transportation of the LNG to market, that the change in the LNG sales model is most clearly seen."

It is perhaps in the midstream part of the LNG value chain, that is, the sale and transportation of LNG to market, that the change in the sales model is most clearly seen. This change is most prominently facilitated by the emergence of the LNG aggregator model with portfolio traders producing a more liquid, fungible market. This model may retain the traditional point-to-point market with destination clauses and a floating pipeline of project-financed LNG carriers linking project-financed onshore liquefaction plants to onshore regasification terminals. However, the market has become much deeper and more complex with the addition of portfolio buyers procuring a mix of spot, short-, medium- and long-term purchases. The availability of floating regasification units (FSRUs and FSUs) opens new jurisdictions to LNG sellers. This, in turn, enables the gasification of markets where domestic or piped gas has never been an option; FSRUs can also boost existing gas markets where domestic gas production is in decline. This transition has also changed the LNG carrier chartering market. New, more flexible chartering terms are emerging to support the mixed portfolio approach of the traders and aggregators.

DOWNSTREAM



The downstream segment of the LNG value chain, i.e. the LNG-to-Power project itself, is, in many ways, the newest part of the market and consequently still evolving in many parts of the world. Whilst the introduction of FSRUs creates infinitely more flexibility, one linked to a dedicated power plant also results in a combination of factors that creates a more complex matrix of project-on-project risks than traditional models may do.

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Just some of the critical issues that need to be effectively addressed to ensure the LNG-to-Power project is successful include:

(i) how supply risks for LNG to countries and regasified LNG to power plants/commercial users may best be addressed;

(ii) the ownership and operations of the FSRU on the one hand and the power plant/transmission lines on the other; and

(iii) the mitigation of electricity/regasified LNG offtake risks.

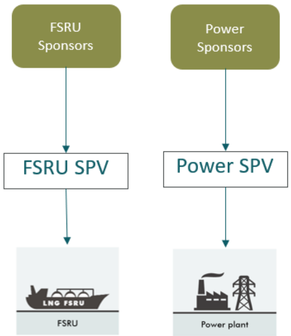
From here on, this article will focus on the above issues.

LNG-TO-POWER RISK MATRIX

CORPORATE/CONTRACTING STRUCTURES AS RISK MITIGANTS

The LNG-to-Power risk matrix impacts each part of the downstream segment of the value chain. The method of addressing each risk will depend on the local conditions in the relevant jurisdiction. A solution in one jurisdiction is unlikely to work in the precise same way in another due to local laws, regulations, taxes and policy approaches. One size does often not fit all. However, structuring, contracting strategies and the available contractual tool box can be used in different combinations to help mitigate the risk matrix that unfolds in each buyer country.

Corporate Structuring



Stand Alone

The simplest corporate structure that can be used in any project is standalone ownership of each project company. This creates complex project-on-project risks but may be necessitated by local law and regulation, for example where gas is the monopoly of one government entity and power the monopoly of another. This may also be seen where one part of the value chain has been deregulated (say power generation) but the other part (gas supply) has not been. Local maritime laws may also impact the structure where foreign ownership restrictions, for example, require standalone ownership of the FSRU. Ultimately, where a standalone structure is required, this creates the highest level of risk because the different sponsors will be more concerned about the risks they face rather than those they may be able to pass on up and down the value chain. Such a structure is perhaps the most difficult to manage as it is not always obvious who the best party to manage a particular risk is and interests of the different players along the value chain are not necessarily aligned. Lenders are also less comfortable with such structures given this risk profile and the increased risk of defaults in parts of the value chain the lenders may not necessarily have security over.

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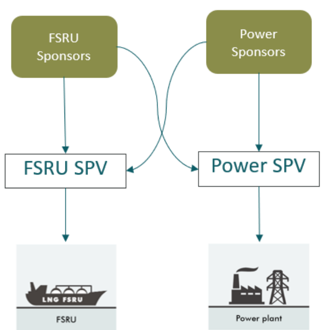
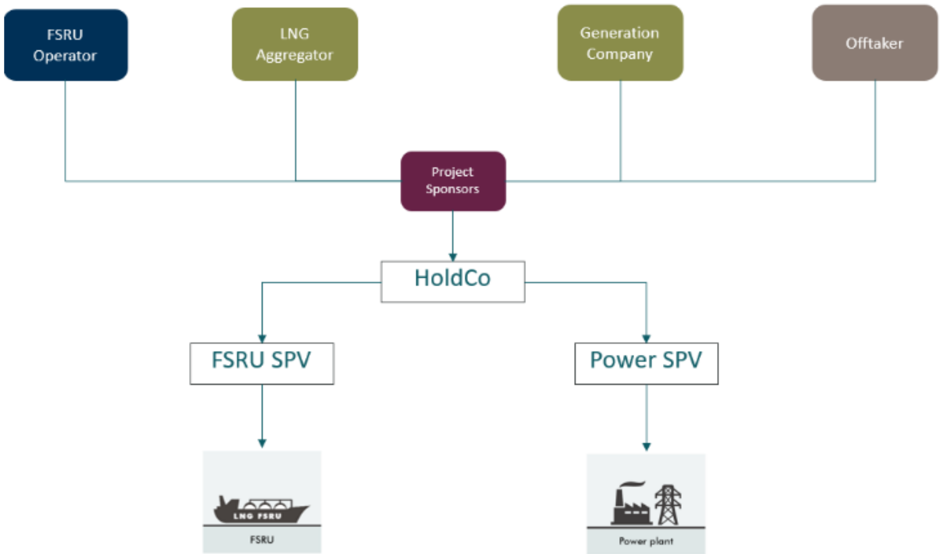


Cross Ownership

The simplest structuring fix for this is to create a certain amount of cross-ownership between project companies, that is, by the power sponsors taking a stake in the FSRU or both sets of sponsors taking a stake in each other's project. Cross-ownership will allow alignment of some of the parties' interests and can provide a risk-reward motivation for both groups of sponsors.

The third structure that is being used is an integrated corporate structure where all sponsors participate in the entire downstream segment. This integrated corporate structure combined with some of the contracting strategies set out further below, more optimally aligns interests within the project as it reduces the number of competing positions so that the overall risk matrix is reduced.

That said, standalone and integrated projects are rarely employed in their purest form. The way they may be combined with each other and elements of cross-ownership will be driven by local ownership restrictions and the risk appetite of the sponsors as well as availability of finance. As ever, local law advice will be key to what can and cannot be achieved through the corporate structure but even the project-on-project risks created by a standalone model may be mitigated to an acceptable level by using the most effective contracting strategies.



Case Study 1: Java 1, Indonesia

Java 1 is an example of an integrated structure combined with cross ownership. The structure was partly driven by Indonesian foreign ownership restrictions in relation to the FSRU. In this structure, PLN was the offtaker under a 25-year PPA. PLN acquired the LNG from the Tangguh LNG project in Indonesia and supplied LNG to the Power consortium which was made up of Pertamina, Sojitz and Marubeni. Due to Indonesian cabotage laws (requiring maritime vessels to be 51% controlled/owned by Indonesian nationals) the FSRU consortium included Humpuss (an Indonesian maritime) group. In addition, MOL was introduced to the equity in the FSRU and also provided O&M services to operate the FSRU for the project. The power plant and FSRU are operated in an integrated manner. Two separate but linked loan agreements financed the projects. The loans incorporate a NEXI-covered loan facility with support from JBIC and ADB. The tenor of the loans was 21 years with cross default and cross collateralisation.

Contract Structuring

The corporate structures mentioned above mandate/facilitate corresponding contractual structures.

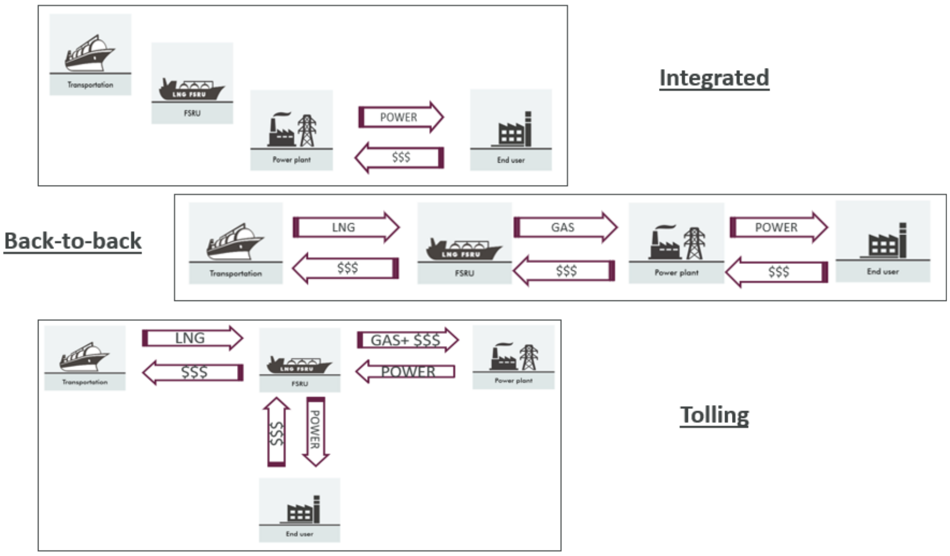
For example, the integrated corporate model often corresponds to an integrated contractual structure where a single project company purchases LNG and owns/hires and operates the FSRU and associated infrastructure, such as the jetty, mooring facilities and gas unloading arms, gas transportation infrastructure as well as the power plant and ultimately sells the power to often government-owned utility offtakers.

From a corporate and contractual structuring point of view this represents the simplest model and avoids separate project entities with resulting contractual complexities between them. However, this model is still quite difficult to finance and there are very few what we would call 'true' integrated projects around. This is particularly true in projects with a single gas source (rather than multiple LNG sources) and a single offtaker (like a powerplant). All the risks will sit with the integrated project company and it must, therefore, be equipped to deal with them effectively. As a result, most of the integrated projects under discussion or construction, were/are being developed either by or in consortium with a gas major who can act as an LNG aggregator and who is also often well versed in electricity production. This is the case, for example, in the Kanbauk project in Myanmar where one of the leading consortium members is Total. Gas majors have the added advantage that they may even be able to circumvent the necessity for project finance by financing the project off their balance sheet (at least in the construction stage).

Where an integrated project is not appropriate, for example because of specific regulatory restrictions on ownership as mentioned previously, mandatory third-party access requirements to the gas/LNG infrastructure or where parts of the supply chain is already operational (such as an existing domestic gas market or IPP), a non-integrated contractual structure may be more appropriate which probably equates to something like the standalone corporate model. This mandates at least a gas hub company (HubCo) and an electricity company (IPPCo) to be put in place. Contractually, this could translate into a back-to-back structure, where risks are passed up or down the value chain to the entity best placed to take those risks. This structure is likely the most complex corporate structure, creating multiple counterparty performance risks and should, in our view, best be avoided in its purest form.

"If buyers along the chain are sufficiently creditworthy, a tolling structure will be able to avoid the need for credit support by HubCo and IPPCo or requirements for it may at least be reduced."

It could also translate into the perhaps more common and easier to manage tolling structure where a, usually government, entity buys the LNG and tolls it through the FSRU which is owned/chartered and operated by HubCo and then IPPCo takes the power via an energy conversion agreement. Gas can also be sold separately by HubCo to gas customers. If buyers along the chain are sufficiently creditworthy, a tolling structure will be able to avoid the need for credit support by HubCo and IPPCo or requirements for it may at least be reduced.



Case Study 2: Pakistan

A tolling structure was chosen for the Engro/Excelerate Energy FSRU-based LNG import terminal in Pakistan, which came on stream in 2015, due to Pakistan's existing gas market and relating pipeline infrastructure. Here, a subsidiary of Engro Corporation owns the immediately onshore LNG import infrastructure whilst Excelerate Energy retains ownership of the FSRU and Sui Southern Gas Company tolls the LNG through the FSRU to transport it to customers along its and Sui Northern Gas Company's pipeline system.

Buyer country-imposed mandatory third-party access requirements will obviously allow increased access to customers and often also multiple LNG supply sources to be put in place, but these requirements will also mandate the need for multiple access agreements to the FSRU and the gas infrastructure which will create new complexities around associated risk of mismatch in terms of LNG scheduling and gas nominations and often also LNG/gas quality. These risks can be mitigated by putting in place an aggregator entity which could either be equipped with shipping capacity to take cargoes FOB and manage cargo diversions itself or be a local LNG buyer/gas selling marketeer who may even own the FSRU/gas infrastructure, that is, HubCo functions as an aggregator, or tolls the LNG through these facilities. In the Pakistan LNG import project, the aggregator role is being played by a domestic trading company, Pakistan State Oil.

KEY RISKS

As we have seen, the more project companies there are involved in an LNG-to-Power project, the higher the contractual complexities and resulting project-on-project risks. Whilst a number of those risks are inherent in complex infrastructure projects of any kind, there are some that are particular to the LNG industry and/or more deeply entrenched in an LNG-to-Power project, particularly if developed in emerging markets.

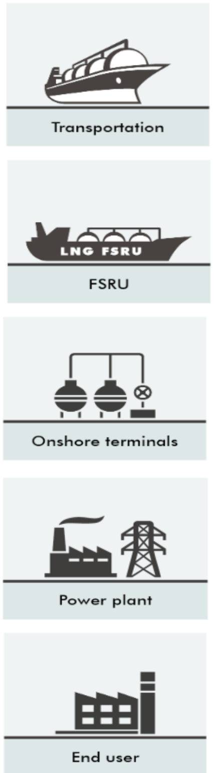
Counterparty Credit Risk

One of the recurring project risks we want to look at in a bit more detail is counterparty credit risk. Whilst it is not unique to LNG, it is rather new to LNG projects which traditionally relied on anchor countries, like Japan and South Korea, where over the years creditworthy buyers created impeccable offtake and payment track records, which underpinned financing of large upstream liquefaction projects.

However, slower demand growth in both these traditional markets and the Western world generally, combined with supply competition from other fuels such as coal, nuclear and renewables sources have forced sellers to turn to emerging markets to sell their LNG. The development of FSRUs has often allowed these markets to access LNG for the first time. They commonly have no buyer, demand or payment history and pose issues of creditworthiness and sometimes also political risk. They are often also smaller, taking smaller LNG volumes (for example where they are designed to bridge the time for domestic gas production to come onstream, and are, therefore, not ideal to underpin project financing).

Accordingly, sellers need to verify sustainability of demand and ability to honour payments all the way from the end user back up to the LNG purchaser. In addition, a seller will seek to incorporate as many contractual tools as available to them, including corporate structuring, government/offtaker guarantees and step-in rights to name a few, as in fact any investor would in other complex projects.

Of course, it is not clear whether a government or utility will be able to honour the guarantee it may have granted. If available, it is advisable for the project to also take the benefit of a project implementation agreement/host government agreement (HGA). In addition, structuring the project in such a way that the project company can make use of bilateral investment treaties with the host country would allow additional protections under which a breach of guarantee can be raised under the relevant treaty rather than having to resort to bringing a claim under the guarantee itself against the government in the host country. There are, however, examples in the market where no government guarantees or implementation agreements were available to the project investors, but the project nevertheless went ahead and was successfully financed. This was the case with the above-mentioned Pakistan project.



Key Risks	Mitigants
Counterparty creditworthiness	• Corporate structuring • Government guarantees and offtake • Step in rights • Bilateral investment treaties
Delay or non-performance by counterparty	• Corporate structuring • Coordinate start up dates along the chain • Funnelling mechanism and build up periods • Alternative LNG / fuel supply and storage • LNG cargo diversion rights • Pass through of FM and liabilities/LDs • Insurance • Step in rights • Pass through of termination rights / damages • Take or pay / ship or pay • Synchronise commissioning and acceptance tests and maintenance periods
Pricing and currency issues	• Corporate structuring • Combination of long term and spot supply and pricing mechanisms • Payment in US$ and GSA/PPA price link to US$ • Diversification of LNG/fuel source and gas/power offtaker • Hedging • Price renegotiations
Market Demand	• Corporate structuring • LNG cargo diversion rights • Alternative LNG / fuel supply • Build up periods • Volume flexibility / storage • Diversification of offtakers • Offtaker guarantees • Take or pay / ship or pay
Political Risk and Change of Law	• Corporate structuring • Government guarantees • Insurance • Adopting floating technologies rather than onshore facilities • Bilateral investment treaties

Delays

Unless the delay risk is effectively managed, delays that occur during the construction phase will hamper the start of cashflow being generated and hinder the repayment of project loans while interest charges continue to accumulate. As a starting point, start dates, commissioning periods and acceptance tests need to be coordinated throughout the in-country contractual chain but also with the start-up of LNG supply. Liabilities for delay, force majeure and termination provisions must be passed through as well, if this risk is to be mitigated effectively.

Where the contracts provide for liquidated damages to be payable on delay, these should ideally be structured so as to keep the entire project whole. However, this may not be feasible given the cost intensity particularly of the upstream project. Therfore, to mitigate construction phase delay, LNG sales contracts will normally contain diversion rights and often also the right to resell the cargo or regasified LNG downstream.

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Having said that, the best mitigation tool in our view is to ensure that the LNG import facilities are in place first, so that the project can start creating some form of revenues and reducing project-on-project risks. For example, LNG could be offloaded into trucks for some small-scale projects in port or to supply the transportation sector or, where gas pipeline infrastructure is in place, regasified LNG can be sold to gas customers even if the power plant and/or transmission lines are not yet ready.

During the operational phase, disruptions due to outages or even market disruption could occur on both the demand and supply sides. Taking the demand side first, again the key contractual tool will be to pass through the main contract terms such as liabilities, force majeure and termination rights, but now the contracts also need to deal with passing through maintenance periods (for example if the FSRU is on dry dock due to class requirements and where there is no replacement available for that time) and seasonal demand swings. Again, the LNG sales agreement will need diversion rights, but the huge cost outlay and lead times involved in developing LNG projects require volume certainty at the final investment decision (FID) stage. This has traditionally been achieved through locking in long-term take-or-pay obligations. Whilst LNG buyers have agreed to take this volume risk in the past, the recent changes in the LNG supply market, whereby supply basically outstrips demand, have meant that buyers are in a position to ask for more contractual flexibility. This flexibility can be provided through lower take-or-pay obligations, shorter contract terms, carry forward rights, volume flexibilities particularly to accommodate seasonality swings in their markets, diversion rights, rights to resell cargoes/gas and demanding certainty of make-up cargoes being available on demand.

Incorporating these flexibility terms alters the traditional risk matrix for sellers and therefore ultimately for lenders. Flexibility will also come at a price and will, therefore, favour mostly cost-efficient, long-established producers who have perhaps already paid off their project loans, for example, Qatari and US LNG producers. Still, in our view, this degree of flexibility will be difficult to offer/maintain, particularly if and when the market flips again and demand outstrips supply. Many forecast that this will happen within the next two or three years due to current capex postponement and reduction as well as new liquefaction projects being delayed. It may, therefore, be better/easier or even essential for buyers to mitigate this risk through buying LNG on a portfolio basis either itself or through an aggregator, the latter of which seems to be fast becoming the new model.

Delays on the supply side can again be mitigated by the buyer conducting its LNG purchase on a portfolio basis as it is perhaps unlikely that all the LNG sources break down or become unavailable at once. If the supply disruption is in the LNG or gas part of the chain, it will be helpful if the power plant can run on dual fuel. However, if that is the case, the power plant will likely be required to run on gas at least to a certain minimum percentage of the time or use a certain percentage volume to ensure at least a minimum gas/LNG demand is secure. Obviously, the availability of storage will be helpful to cushion supply disruptions and give demand flexibility, either in the form of onshore storage tanks or floating LNG storage barge(s)/moored LNG carriers.

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Pricing

LNG pricing formulas are customarily based on a link to the local/regional fuel competitor, such as oil, naphtha or gas. Traditional anchor countries/LNG buyers used to be willing to pay for the LNG according to a price formula that was pretty much regionally entrenched due to the market at that time being sliced up into Asia-Pacific and Atlantic basins. Accordingly, producers in Asia would sell to buyers in the same region and the same was true for sellers in the Atlantic basin (for example in West and North Africa) who would mostly sell into Europe. Traditionally there was virtually no 'interference' between these markets.

However, the emergence of swing suppliers in the Middle East (like Qatar) and, later on, low cost swing producers in the US as well as large portfolio players, has seen a change to the sale of cargoes in both east and west. This has been due to the location of the liquefaction plants as well as to the Suez and Panama canals opening up to the LNG trade. Over time this has eroded the well-tested traditional Atlantic/Asia-Pacific model and introduced greater competition for traditional producers. It has also provided more choice and flexibility for buyers. This is not just in terms of LNG volumes but also pricing formulas/competing fuel indexation. The best example perhaps is the amount of LNG being sold in Asia that is indexed to Henry Hub rather than the traditional JCC (Japanese Crude Cocktail). The introduction of a price 'floor' and 'ceiling' (which was mainly used to protect buyers and sellers against major price spikes) are now also less common.

However, parties continue to give themselves the right to review the agreed price formula either periodically or upon the trigger of a certain event occurring, such as the competing fuels changing, markets getting liberalised and restructured and, as a consequence, tariffs being introduced, as well as liquidity in the market constantly increasing not least due to the upcoming expiry of a number of long-term supply agreements into Japan and South Korea.

Due to events like these and more demand currently being created in Asia than in other parts of the world, the initial LNG 'action' has largely moved away from Europe to Asia. Having said that, as long as there is a demand slump, introducing aggregators seems to only push the bucket further down the chain rather than truly

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solving the demand issue for LNG producers. A persistent lack of demand may, therefore, ultimately mean that producers have to shut in gas production, particularly in the case of floating liquefaction plants which have less storage capacity available than onshore plants do. Unless they surround themselves with barges or perhaps use the gas to produce blue hydrogen, as and when that market is up and running.

To create new demand for their LNG, aggregators and traders are moving down the value chain and looking to 'gasify' new markets and support the deployment of new FSRUs and the development of new LNG-to-Power projects. Signs of this activity can clearly be seen in Bangladesh, Sri Lanka, Myanmar and Vietnam. We expect the build out of LNG-to-Power projects across Asia-Pacific to accelerate especially as countries look to transition away from coal.

This movement to Asia can also be seen in the emergence of Singapore as an LNG trading hub. In its simplest form this hub manifests itself in the increase in LNG traders located in Singapore. In 2014 the Monetary Authority of Singapore (MAS) noted there were 20 LNG traders registered. By 2018, the number was 45. The Straits Time reports Singapore Minister of Trade and Industry Chan Chun Sing as noting that there are now more than 50 LNG traders located in Singapore[2]. The centralisation of the traders is also being supported by new trading platforms and market information. S&P Global Platts first published the Japan Korea Marker in February 2009. This is now being seen more and more as an option for pricing. As mentioned earlier, pricing is often indexation linked to a basket of a physical gas trading hub (such as Henry Hub, TTF or NBP), a crude pricing marker such as the Japanese Crude Cocktail or JKM.

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Finally, Singapore is also developing a physical trading presence through the creation of LNG storage and transhipment as well as LNG bunkering for the growing fleet of LNG-fuelled ships that are passing through the city state.

[2] https://www.straitstimes.com/business/economy/more-firms-setting-up-lng-desks-in-singapore-chan-chun-sing

FOR MORE INFORMATION

Should you like to discuss anything covered in this article, please speak with a member of our team below or your regular contact at WFW.

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