THE OXFORD INSTITUTE FOR ENERGY STUDIES

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LNG Finance - will lenders accommodate the changing environment?

1. Summary[1]

The LNG industry faces unprecedented changes. It is in transition towards market-based trading; the COVID crisis has exacerbated an already oversupplied market and the speed and pattern of demand recovery is unclear. Longer term, climate change poses new challenges. The range of uncertainty, in the level of future demand and pattern of supply, seems higher than usual. Yet most forecasts show a need for additional LNG liquefaction, shipping and regasification capacity that will require significant investment over the next decade. This paper addresses the impact of these challenges on the lending communities, and their ability to continue to provide the desired finance.

Despite all the uncertainty, a number of conclusions can be drawn. First, lenders may be less able than developers to accommodate the transition towards market-based trading and pricing. For LNG sales into Asia, a change from oil to gas price indexation is facing some resistance from lenders, but it is likely be accepted on a gradual basis as the market deepens. For any LNG sales, departure from long-term offtake contracts would be more problematic. Project finance lenders (to any industry) almost always require long-term volume offtake commitments to support the debt, and this is likely to continue for LNG. Some accommodation may be possible, such as for a proportion of offtake to be uncontracted at final investment decision (FID) or sales and purchase agreement (SPA) terms of less than 20 years, but the basic requirement for contracted volumes sufficient to repay debt is unlikely to change.

Second, climate change creates new uncertainties, as changes in government policies could have a big impact on gas demand, positively or negatively. In addition, lenders are subject to growing pressure from the public, environmental lobbyists and governments to contribute to climate change response, which could lead to step changes in their lending policies. European banks and Export Credit Agencies (ECAs) are currently under pressure to cease financing fracking-related projects which could bar them from North American LNG projects. Further pressure could lead to some institutions ceasing to fund any hydrocarbon project, as they have done for coal. The finance markets are deep and varied and likely to continue funding the LNG industry, but with increased environmental vetting.

Many LNG developers will not require project finance but for those that do, the amount and terms of the finance could be critical. To a greater extent than before, lenders' needs could impact which projects reach FID and on what terms.

[1] The information presented in this Insight does not constitute financial advice in any way whatsoever. Nothing herein constitutes an investment or buying or selling recommendation, not should any data be relied upon for any investment or buying and selling activities.

Robin Baker, Visiting Research Fellow, OIES

2. Introduction

Limited recourse project finance[2] has strongly supported the LNG industry over the last 35 years, funding around 40 per cent of the total capital for all major liquefaction projects.[3] Aside from the majors, many companies would have struggled to raise the necessary finance otherwise. Project finance requires extensive due diligence,[4] but the principal commercial structures required by lenders, such as for long-term Gas Sales Agreements (GSAs) and LNG Sales and Purchase Agreements (SPAs), have not differed greatly from those of the sponsors; most projects, whether project financed or not, have relied on long-term SPAs or long-term capacity agreements from strong, reliable buyers for the planned production throughout and beyond the life of the loan.[5]

Is this all about to change? Two major changes in the industry will have an impact on its finance. First of these is the transition of the LNG business, outlined in Section 4, from the traditional model of, primarily, bilateral trades, to more market-based trading. Deregulation and liberalization in much of Europe has led to a deep open market for gas, allowing LNG to be sold at European hub gas prices. Asian markets are moving in the same direction with new LNG importing markets bringing a greater diversity of buyers and increasing volumes of LNG sold on a short-term or spot basis. However, the process is less advanced than in Europe. Ledesma and Fulwood noted these changes in 2019,[6] and suggested that further development towards a truly merchant model could see all trades at market prices, potentially without long-term contracts.

The second change is demand uncertainty, due to both short- and long-term issues. In the short-term, many SPAs are under stress in their volume commitments and pricing, from issues dating before, but exacerbated by, the COVID-19 crisis.[7] Offtakers from the wave of North American liquefaction projects have had to pay for liquefaction capacity without lifting the LNG, and the 'Henry Hub plus fixed' pricing seems increasingly challenged.

The collapse in demand is seen as delaying many new FIDs, but longer term, the demand outlook of the IEA (Figure 1)[8] suggests a strong need for gas, particularly across Asia, as an important, if transitional, fuel. For any specific project, lenders will commission a market study by a recognized industry consultant, but they will also review published projections as they seek to assess the risk to the assumptions. In this context, IEA's annual World Energy Outlook provides an important view. Unlike many project-specific market studies, the IEA considers differing scenarios (World Energy Report 2019: Current Policies, Stated Policies and Sustainable Development) which give some quantification of the uncertainties arising from government climate change policies.

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[2] Project finance is debt finance advanced to a project, to fund project costs, and repayable from project cash flows. It may be described as non-recourse in which there is no recourse to sponsors, but this is uncommon. More often there is some recourse such as guarantees until completion or an undertaking to complete the project, undertakings to operate the plant and/or provide technical assistance, and various 'negative pledges' such as not to sell the interest in the project; but generally sponsors are not obliged to repay the debt in the event of cash flow insufficiency. Hence the usual term Limited Recourse.

[3] Baker, R., Rich, F. C., and Anselmi, J. J. (2010). 'The Future of LNG Finance', *Petroleum Economist*, 1 March. Up to 2010 this figure was around 50%, but has since fallen due to a number of very large projects with strong sponsors including Australian Gorgon, Gladstone and Queensland Curtis, Indonesian Tangguh Train 3, and LNG Canada (under construction), not seeking project finance. https://www.petroleum-economist.com/articles/midstream-downstream/lng/2010/the-future-of-lng-finance

[4] Lenders due diligence is outlined in Appendix 3.

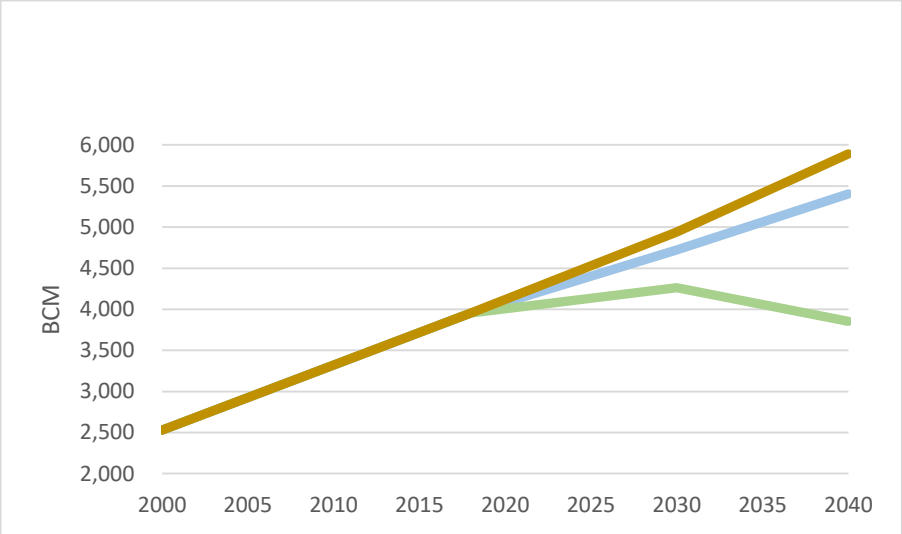
[5] Major liquefaction projects developed by the integrated oil and gas companies, including Gorgon, Wheatstone, Tangguh, Gladstone and Mozambique, have largely been developed with long-term SPAs, though more recently some, including LNG Canada, rely on sponsors equity lifting.

[6] Ledesma, D. and Fulwood, M. (2019). 'New Players, New Models – a research think piece', Oxford: OIES, March.

[7] Rogers, H. V. and Stern, J. (2014). 'Challenges to JCC Pricing in Asian LNG Markets', Oxford: OIES, 81. In February 2014, Rogers and Stern described the issues with oil indexation in Asian SPAs and the expectation and desirability of a transition to market pricing.

[8] At the time of writing, the International Energy Agency's (IEA) World Energy Outlook 2019 was the latest published. https://www.iea.org/reports/world-energy-outlook-2019. Since then, WEO 2020 has come out and is referenced in footnotes where appropriate.

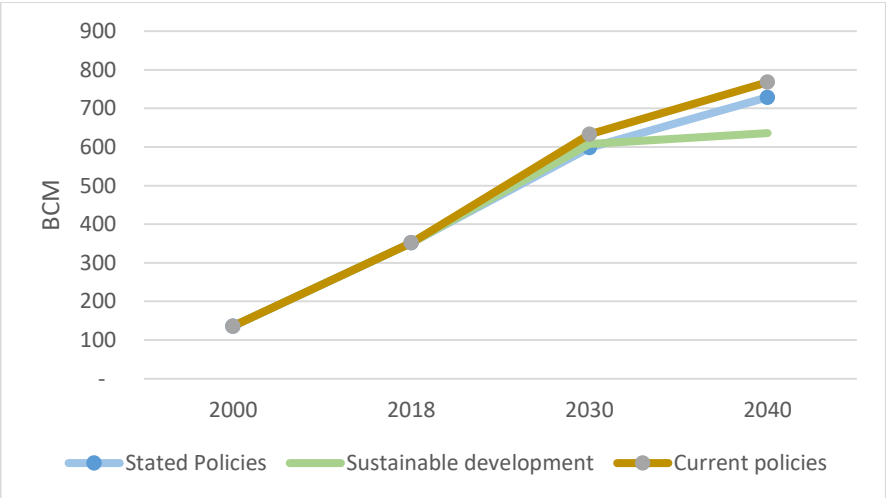
Figure 1: World gas demand



Source: IEA World Energy Outlook 2019

These scenarios show a substantial variation and, in one scenario, a fall in gas demand post 2030, though taking account of depletion, not enough to reduce LNG demand.

Figure 2: World LNG demand



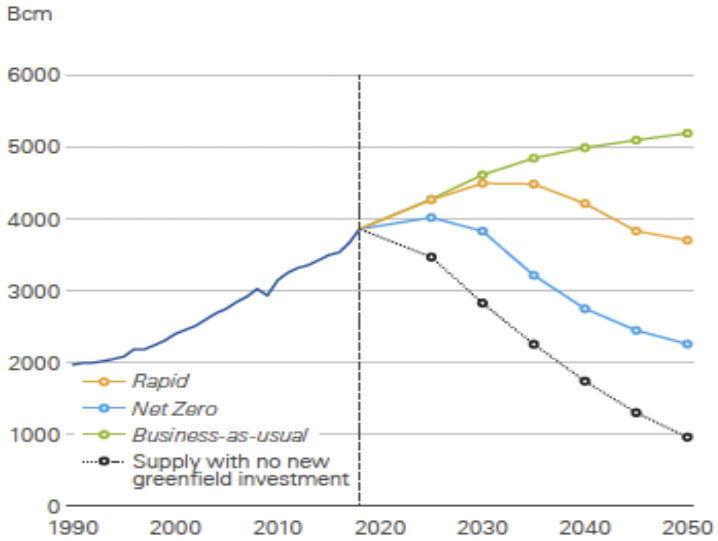
Source: IEA World Energy Outlook 2019

Given the challenges of meeting either Rapid or Net Zero scenarios, there remains an expectation that substantial new LNG capacity will be needed, but with a wide range of uncertainty as to just how much.[9] This uncertainty seems to be widening. BP's recent Energy Outlook 2020, shows total global gas demand in its Net Zero scenario falling to less than half that in its Business-as-Usual scenario by 2050 (Figure 3).[10]

[9] Breen, P. (2020). Presentation to Gastech. https://www.upstreamonline.com/coronavirus/expert-raises-prospect-of-no-new-lng-projects-after-qatar-expansion/2-1-874621

[10] IEA World Energy Outlook 2020. https://www.iea.org/reports/world-energy-outlook-2020

Figure 3: BP Energy Outlook, consumption and production of natural gas



Source: BP Energy Outlook 2020

This paper examines the likely challenges in raising debt for future LNG projects, and specifically whether lenders will accept a fully traded gas market with gas market pricing and absence of long-term contracts.

3. LNG Finance

3.1 LNG finance to date

LNG finance has been provided primarily by commercial banks, export credit agencies and, less often, debt capital markets and multilateral agencies (Appendix 1). Banks have been financing LNG projects since the early days of the industry in the mid 1980's.[11] Supported by sound economics, strong sponsors and reliable long-term offtake contracts, the track record has been good with few, if any, defaults. Qatar's Qatargas and Rasgas projects were early models with outstanding reserve base, strong project management, completion guarantees from strong sponsors and 20 year sales contracts (SPAs) for the full production from strong, largely state-sector, monopoly buyers. Political risk was deemed to be modest as all parties had a strong incentive for the project to succeed, and being export projects with offshore revenues in US dollars from investment grade buyers, the exposure to producing country political risk was low. Banks evaluate country risks to a project as a product of the country risk rating and the relative exposure of the specific project to risks in that country. This generally produced a low risk category for LNG projects due to the fully contracted offshore revenues,[12] and enabled banks to fund LNG projects in countries such as Yemen, Nigeria and Papua New Guinea (PNG) which would have struggled to raise long-term debt otherwise. Thus having secure, long-term volume commitments from creditworthy buyers has been central to most LNG finance.

Whilst almost all early projects were based on oil-indexed SPAs, Qatargas was later to finance Qatargas 2, supported by project finance, with sales by the sponsors, Qatar Petroleum (QP) and ExxonMobil, into the UK at UK gas market prices. Other projects are understood to have sold a percentage at

[11] The US$1.4 billion loan to Woodside Petroleum in 1985 for its share of the Australian North West Shelf project was one of the first by an international bank syndicate.

[12] An early example was the Bontang finances which survived the Asian financial crisis with minimal impact, in contrast to most country and corporate debt which had to be rescheduled.

European gas prices and, given the depth of trading in these markets, this is considered acceptable by lenders.

In 2015, Cheniere Energy achieved FID on the first LNG trains at their LNG import facilities at Sabine Pass, converting the site to an import/export facility and starting a wave of new LNG export capacity from North America. Sabine Pass negotiated SPAs indexed to Henry Hub gas prices grossed up for fuel and loss, plus a fixed cost for plant processing costs and return. Most US projects to follow used this model[13] which provided a secure, predictable income stream to the liquefaction plant, allowing a high level of debt finance.

In summary, lenders have to date followed, rather than dictated, commercial SPA terms, and have financed projects where the LNG sales price is indexed to any of oil, EU gas market prices or US gas market prices. The common feature of all of these has been fixed contractual volume commitments extending well beyond the life of the loan.[14] With volumes committed, lenders were able to take a view on price risk, taking comfort that, however priced, terms were broadly in line with industry norms. Recent US, and some international, projects differed in that a tolling or other pass through price structure left the project and its lenders with a fixed revenue stream independent of the LNG price. Provided the party taking the price risk was of sufficient credit standing, this presented an even more financeable structure.

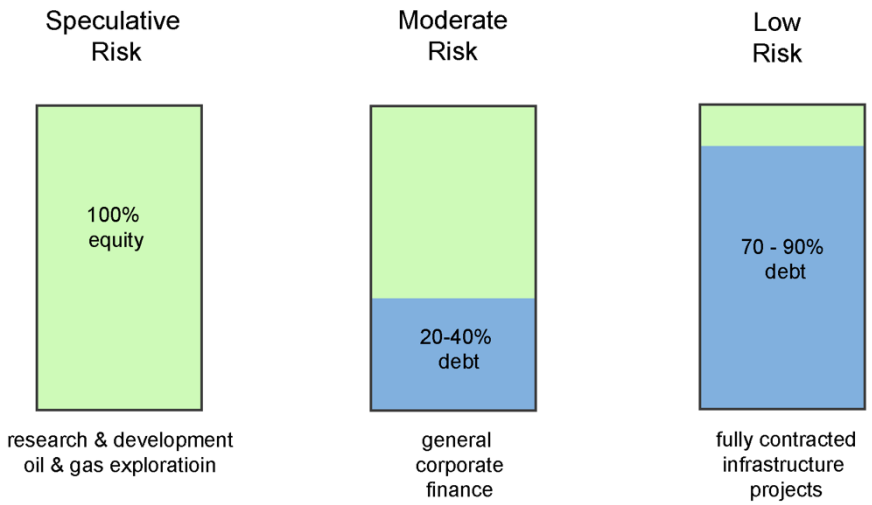
3.2 Why project finance?

Efficient markets theory suggests that, in an ideal world and aside from tax considerations, the capital structure of a project should not impact the investment decision[15] – a view traditionally taken by most major oil companies. Nevertheless, these companies have frequently sought project finance for their LNG projects. The reasons are varied (see Appendix 2), but the most common is probably because weaker partners are less able to raise the finance on their own balance sheets. Whilst there are other means to address this need, whether by single company finance[16], or by 'industry carry' arrangements,[17] these have rarely been used in LNG and project finance remains by far the most common.

Among the other reasons for project finance, there is one – Infrastructure Finance – that may be increasing in importance. Most companies, whether for tax relief on interest or other imperfections to efficient markets theory, seek a mix of debt and equity finance, taking on as much (cheaper) debt as can be tolerated comfortably within the risk profile of the firm.

[13] More commonly a tolling agreement, which achieved the same economic effect – see Section 3.3 Commercial Structures.
[14] Most SPAs were for sales over 20 years from first gas; compared with loans of up to 12 years from completion.
[15] The Modigliani-Miller Theorem suggests that, in an efficient market, the value of a firm (which could be a company or project) is dependent on its future cash flows and is independent of its capital structure. Under this theorem, ignoring tax and assuming and fully efficient capital markets, if the firm takes on more debt, the cost of its remaining equity increases such that the total capital cost is unchanged. The theory assumes perfect knowledge of the business by investors, which is not the case for most projects or companies.
[16] Such as Woodside's share of the early North West Shelf developments, where an unincorporated joint venture structure allowed Woodside to finance its 1/6th share of the project separately from the other sponsors.
[17] 'Industry Carry' arrangements were common in the early days of North Sea oil development where a small company, having discovered reserves, partnered with a stronger company who agreed to carry the weaker company's costs, for a (larger) share of its profits. It has not been common (if used at all) in LNG finance, where the weaker party is often the host government who would likely find such an arrangement too onerous.

Figure 4: Typical leverage



Source: Author

These funding patterns also match the expectations of equity investors. Investors and fund managers evaluate stocks sector by sector with expectations as to the risk profile in each sector. For example, pension funds and insurance companies invest largely in secure long-term assets with a steady, low risk income yielding a return above the risk-free rate of government bonds. Fully contracted infrastructure projects provide the ideal investment, and their low risk profile allows a high level of debt, up to around 90 per cent. Investors in oil and gas companies seek a different, higher, risk and return and will not necessarily adjust their return criteria to account for any lower, infrastructure assets held by such company.[18] Perhaps for this reason, oil and gas companies have not generally invested downstream into regulated power generation and have been selling off other infrastructure assets such as pipelines, to infrastructure funds.

The implications for LNG finance are two-fold. First, project finance can fund a substantial proportion of the capital, reducing the amount of expensive equity priced at the sponsors cost of capital. Integrated LNG projects (where the shareholders are the same across the upstream and liquefaction parts of the chain) have typically been in the medium to low risk range and have been funded with up to 70 per cent debt.

Second, by structuring the LNG plant as an infrastructure project with a secure contractual revenue may allow it to be wholly financed in the financial markets with a combination of project finance debt and infrastructure funding equity, at an overall cost markedly less than if it were owned by an oil and gas company. This approach has been widely adopted by US export projects as a means to access capital at attractive rates. But it requires a commercial structure with appropriate allocation of risk and return (discussed in Section 3.3 below) and the equity component from infrastructure funds is harder to obtain for projects in emerging markets.

3.3 Commercial structures

Structuring the finance for a project is largely an exercise in allocating risk and return, thus a key determinant to finance is the commercial structure.

Many LNG projects are **integrated** projects including all assets from wells through to LNG loading facilities and (for delivery ex-ship (DES) supplies) ships. This presents a simple structure, often with significant value in the reserves beyond the 20 year SPA period. Examples that were successfully

[18] In theory, and to some extent in practice, investors can look at the beta value of a company's stock and adjust their return expectations accordingly. Beta is a measure of the volatility of that stock that correlates with the market against the volatility of the market on average – i.e. it is an indication of the riskiness of the stock, ignoring specific risk which can be diversified away.

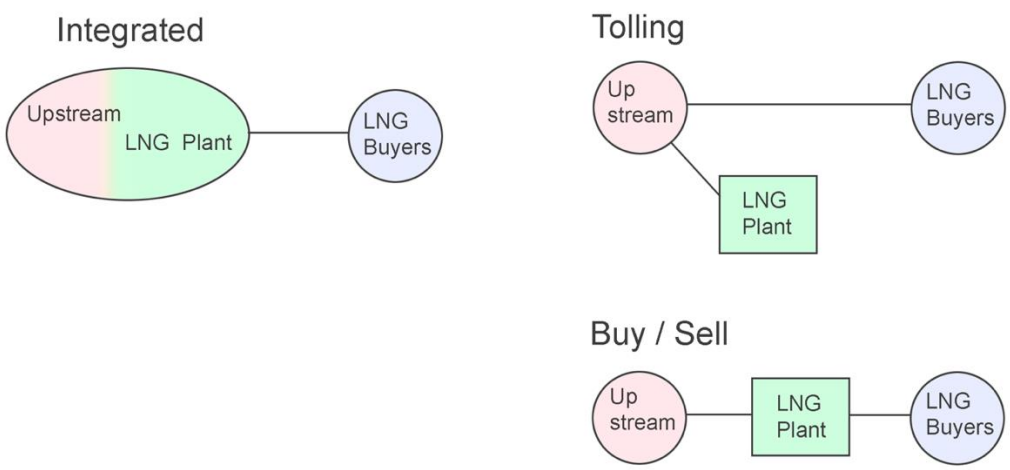
financed on this basis include Woodside Petroleum, the Qatari projects and two of the largest ever project finances: Ichthys LNG and Yamal LNG.

Others use a **non-integrated model** whereby a company is set up to own the LNG plant, taking gas from a separate upstream entity. The upstream and midstream parts of the chain may have separate or common ownership, but they are commercially distinct, linked by commercial agreements which determine the allocation of risk and reward between the two, either as:

a) a buy-and-sell model, where the plant company buys feed gas under a long-term GSA, and sells LNG to buyers under long-term SPAs (examples are Egyptian LNG and Oman LNG); or

b) a tolling model,[19] where the plant company makes liquefaction capacity available to the producers for a processing fee, or toll, such that the upstream company owns the hydrocarbons throughout, producing gas and selling LNG to buyers under long-term SPAs (Atlantic LNG Train 4).

Figure 5: Commercial models



Source: Author

The wave of US projects from Sabine Pass have generally used tolling or buy-and-sell structures where, in each case, the price of LNG to the buyer includes a gas price linked to spot US gas prices, plus a fixed component representing the liquefaction cost.[20] This has allowed the capital-intensive liquefaction plant to be structured and financed as a low risk infrastructure project, often allowing more finance than could be raised by the developers themselves, and at an attractive cost.

The key difference between these models is their differing ability to allocate risk and return between the various parties. The Buy/Sell model has the greatest flexibility, allowing placement of risk and return with any of upstream, midstream or downstream players (Figure 6). The Tolling model provides similar flexibility, but is unlikely to be used for the Market Pricing allocation.

[19] The Indonesian trustee borrower model in the Bontang projects is a form of tolling model. The plant is owned by Pertamina and 100% debt financed, with revenues paid into an offshore trust account from which a portion is made available for debt service on the plant, such that upstream producers receive the residual netback, after all plant costs and government take.
[20] Sabine Pass used the buy and sell model, buying the gas on the market and selling to the offtaker at Henry Hub + 15% plus a fixed amount for the liquefaction cost, whereas others have used the tolling model where the offtakers have to buy gas in the market themselves then pay the tolling fee. The economic impact on the buyers is the same.

Figure 6: Allocation of risk and return

	Market Pricing	Cost-Plus Pricing	Netback Pricing
GSA Price basis	Sellers market price	Sellers market price	Buyers market price less processing cost
SPA Price basis	Buyers market price	Sellers market price plus processing cost	Buyers market price
Risk and return primarily with:	Midstream (LNG Plant)	Downstream (LNG Buyer)	Upstream (Gas Seller)

Source: Author

Each of the three commercial models, integrated, tolling and buy-sell, are potentially financeable and have been financed. Integrated may be favoured for its simplicity and the, often substantial, value in upstream reserves, but the other models have provided highly bankable structures. The key, for lenders, is how the risks are allocated, as discussed in Section 3.4 below. Of the risk allocation models of Figure 6, the Market Pricing Model is included for completeness but is not generally used as it places all the price risk, of gas and LNG, with the LNG plant company.

3.4 Lenders risk analysis

Although lender groups differ somewhat in their credit analysis (see Appendix 3), their basic approach is very similar and will (or at least should) include the following steps:[21]

1. **Does the project bring real value?**

   What is the project for; is it of real benefit and is it competitive?

2. **Is there a fair and appropriate allocation of risk and reward?**

   Any LNG project will have an extensive list of counterparties with some involvement in the project (Figure 7). Lenders will want to understand the role of each counterparty, what the project is relying on them to do or not do and if they have the ability, incentive, and obligation to perform accordingly. A clear legal obligation, as in a construction contract or SPA, is necessary but not sufficient. If that party cannot or will not perform, it is unlikely that the contract will provide adequate compensation. So ability and incentive are crucial.

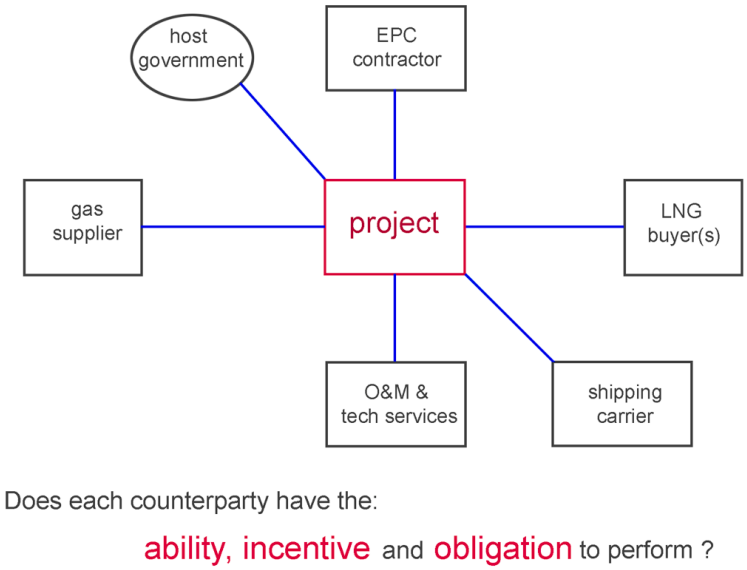
3. **What could go wrong – the sensitivity analysis**

   Lenders, unlike equity investors, do not share in the upside if the project performs better than expected, and expect to be protected from downside risk in all reasonable risk scenarios. Sensitivity analysis tests the ability of the project to service its debt under a range of circumstances. These may be specific to the project, but will include: construction cost overrun and delay; operational performance; operating costs; finance costs; market volume and price risk; feedstock supply risk; competitive risks, and governmental and country risks. Of these, the LNG price is a major uncertainty and lenders will stress test cash flows against both continuing low prices and a shorter term severe downturn. They will also calculate the breakeven price at which debt is just repaid and will expect this to be comfortably below their range of price expectations.

Behind this analysis is a recognition that the only source of repayment is cash received from sales, hence assurance that the LNG will be sold at the expected price and volume is paramount.

[21] This is the author's experience and description of the credit process, having worked in energy finance for US and European commercial banks over 30 years.

Figure 7: Counterparty risk



Source: Author

Many LNG projects have comfortably met these credit criteria and achieved project finance for up to around 70 per cent of total capital cost. LNG finance is popular with those institutions – European banks and ECAs, and others – that have built the necessary expertise, and these markets will continue to support the industry through its next phase of development. But not without challenges, described in Sections 4 and 5 below, of which some, but not all, will be accommodated by lenders.

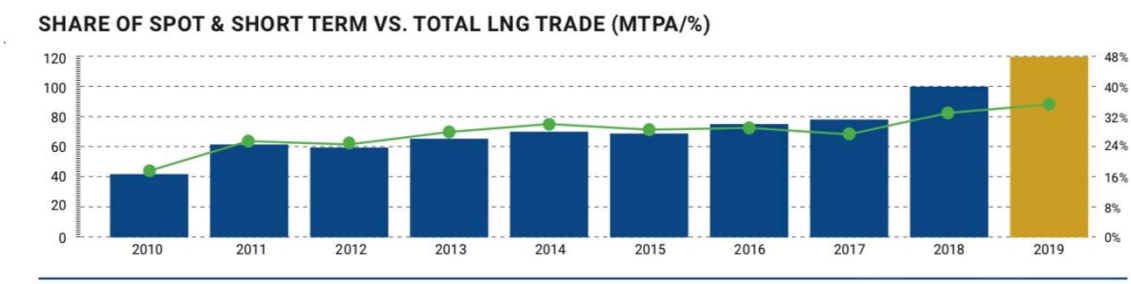
4. The Need for Change

4.1 Progress towards a deep open market

The present LNG contractual structure grew from the early sales of LNG to Japan, replacing low sulphur fuel oil in power generation, with large state-owned utilities buying LNG and selling into regulated gas and power markets. It was, to some extent, a cost-plus business with oil-indexed pricing passed through to consumers. With few large trades, security of supply and offtake were critical to both buyers and sellers, hence the need for long-term SPAs. Oil price indexation made sense for both parties.

Today there are some 50 liquefaction plants,[22] over 100 regas terminals including over 60 in Asia,[23] and a growing market for short-term and spot traded products.

Figure 8: Share of spot and short sales versus total LNG trade



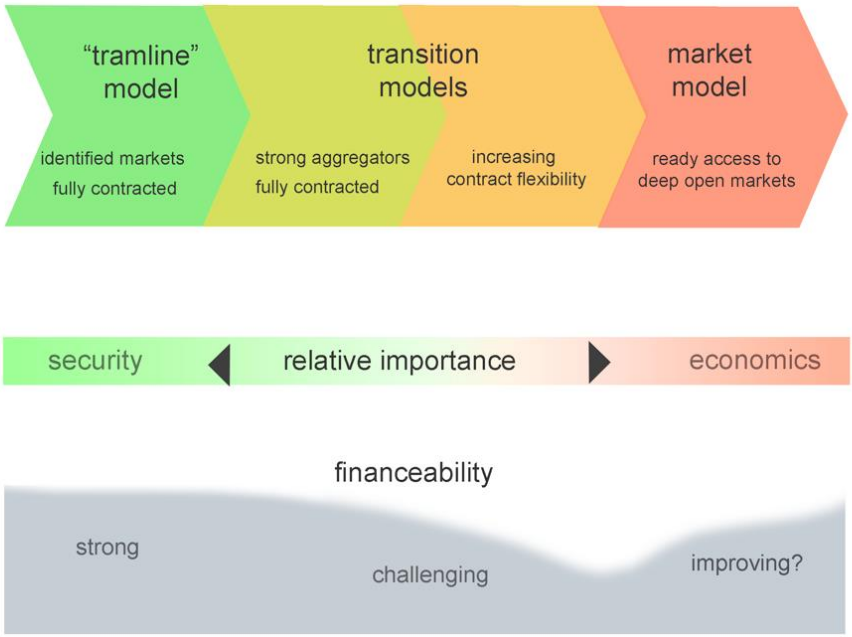
Source: GIIGNL Annual Report 2020 Edition, 35

[22] IGU World LNG Report 2019
[23] GIIGNL – Annual Report 2020

Ledesma and Fulwood in their 2019 paper[24] noted these trends towards a global LNG market with multiple buyers and sellers, a growing percentage of trade under spot or short-term contracts and some convergence of regional prices. They noted various contract models that were, or could be, used to replace the traditional 'tramline' model of point to point long-term contracts, and suggested that further development towards a truly merchant model could obviate the need for long-term contracts. In a liquid, freely traded market with transparent price indices, as crude oil, sellers can always sell and buyers can always buy at market price.

Much has happened since this publication, and it is hard to predict how quickly the world will recover from COVID-19 nor what longer term changes it might have initiated. There remains a large gap between targets for net zero energy and current government policies which makes predicting future demand particularly difficult. Besides demand uncertainty, Asian markets are largely independent of each other and still controlled by a small number of major gas distributors. LNG trading is, as yet, still in transition (Figure 9).

Figure 9: LNG in transition



Source: Adapted from 'Debt Finance in LNG Markets – it's going to change'; Robin Baker, SGCIB, LNG17, Houston 2013

Buyers may seek to avoid long-term commitments, particularly beyond, say, ten years (that is, 15 years from FID) when the demand outlook is less clear. On the other hand, developers may be reluctant to reach FID on major new investments without some long-term committed offtake at least for sales into Asia.[25] The answer will vary project to project, but may see developers taking FID with reduced offtake commitments and some reliance on assumed ability to sell (or contract at a later date) uncontracted volumes.

4.1 The competitive environment

The present buyers' market with excess productive capacity has created a highly competitive environment with depressed prices and some shut in capacity. Demand will pick up and the industry can expect the cyclicality typical of a capital-intensive business, but the move towards a global traded market heightens competition where suppliers will focus more on competitive costs. Having a

[24] Ledesma, D. and Fulwood, M. (2019). 'New Players, New Models – a research think piece', Oxford: OIES, March.
[25] But for the increasing volumes from existing projects where contracts have expired, and from debottlenecking and expansions, there may be less, or no, need for long-term SPAs.

competitively low all-in production cost is critical to development approval. The implications for finance are twofold. First, lenders will similarly focus on competitivity and will want to ensure the projects they finance have competitively low all in costs. Second, finance may have to contribute to cost reduction through management of risk and return between segments of the business as described in Section 3.2 above.

4.2 North American models

There is a further challenge with North American export projects, in how to manage the basis risk between North American and Asian market pricing. Projects to date have placed the price risk with buyers who pay for feed gas at a Henry Hub indexed price, plus a fixed charge for liquefaction capacity. They are not obliged to lift LNG but pay a capacity charge, or processing fee, whether or not they lift. For a period during 2020, European and Asian LNG prices fell below US prices plus processing costs during which time many buyers ceased to lift LNG.

With Asian LNG becoming more market-based, the US model would not seem to be attractive for future supplies, particularly in a buyers' market. A more sustainable model might be for gas suppliers to take the basis risk by receiving a netback of LNG market price (for example, JKM) less processing costs. That would also provide a secure, contractual revenue stream against which the liquefaction plant could be financed and give buyers the security of LNG supplies at a relevant Asian market price. However, all but the larger gas producers may struggle to commit long-term supplies on this basis when field production profiles are shorter; and if the gas supplier is not able to supply at some future date, it may not be possible to obtain replacement supplies if the netback does not then cover local market prices. This may be a solution with larger gas suppliers,[26] but challenging for smaller players.

Put another way, US projects can have attractively low all-in costs, but in cash cost terms buying feedstock at market prices, they cannot compete in Asian markets with most international projects. This issue might be partially mitigated if developers or buyers were to invest in the upstream, but it does not wholly remove the challenge of competing with international projects where, at the margin, there is no alternative use for the gas.

5. Lenders Response

Amongst the likely next wave of developments there are a number of large LNG projects that may not need project finance. For example, Qatar, Russia and Australia have strong International Oil Company (IOC) and/or state sponsorship and are likely to have access to other sources of finance. Others that need or choose project financing may finders lenders struggling with the following issues:

5.1 Price risk and volatility

Lenders have already accepted European gas market price indexation[27] where there is a deep market with transparent price indices. Asia is more of a challenge. There is not, and not likely to be, a single Asian gas market. That would require pipeline connectivity such as in North America and much of Europe. There are large country-specific gas markets in Asia which are liberalizing but have some way to go to reach the European or North American level of a transparent, fully traded market. In each of the main markets of China, Taiwan, South Korea and each region in Japan there are one or two dominant, often state-owned, gas distributors, and limited open-access provisions or other market protections. The direction is toward deregulation and liberalization, but progress is slow.

In the absence of an Asian gas market, an Asian LNG market is beginning to develop around Japan Korea Marker (JKM), the principal regional index. Heather[28] set out five key elements of a liquid market,

[26]For example, in June 2019 Cheniere signed a gas supply agreement with Apache Corporation for supply of gas on a netback basis, priced at LNG market price less processing costs. https://d1io3yog0oux5.cloudfront.net/_234f1795a70c3c19208bf05f284d6975/cheniere/news/2019-06-03_Cheniere_Corpus_Christi_Stage_III_and_Apache_Sign__183.pdf

[27] Qatargas and Yamal LNG both sell LNG into the UK at UK gas market prices.

[28] Heather, P. (2019). 'European traded gas hubs: a decade of change'. Oxford: OIES, Energy Insight 55.

identifying churn rate (the ratio of traded volume to actual physical throughput) as the most important. On this measure, JKM is far from a deep traded index.

Figure 10: Traded hubs for gas and LNG

Hub	Churn Rate	Liquidity
Henry Hub	45.5 [1]	Very liquid
TTF (outside of Netherlands where churn rate is higher)	17.9 [1]	Liquid
NBP (Britain)	14.3	Mature
JKM	0.54 [2]	Illiquid

Source: 'European Traded Gas Hubs: the supremacy of TTF'. Heather, P. (2020). OIES.
Note: 1 trading / consumption - 2 trading / LNG imports

Nevertheless lenders are starting to be presented with contracts based on JKM, and indications are that they are likely to accept this for at least a portion of the offtake, and that this will increase over time as liquidity increases. In December 2018, Tellurian and Vitol signed a Memorandum of Understanding (MOU) for a 15 year sale of 1.5 mtpa LNG from the proposed Driftwood LNG project with the price indexed to JKM, with the intent that the project would be project financed. Cheniere is also looking at indexation to JKM for a portion of its sales.[29]

Besides the index, lenders are more than usually focused on commodity price risk since the recent crash in oil and gas prices. Brent fell below $20/bbl in April this year giving an LNG price landed Asia of around $3.0/MMBtu[30] from a typical oil-indexed contract. JKM fell further to $2.11/MMBtu (Figure 11). These prices are well below US production costs so would be unlikely to sustain at these levels. Nevertheless, such a price collapse could recur in the event of surplus and lenders may deduce from these data that Asian gas prices are more volatile than oil. This could lead to a reduced low case and more severe stress tests against short-term price crashes,[31] resulting in lower achievable leverage.

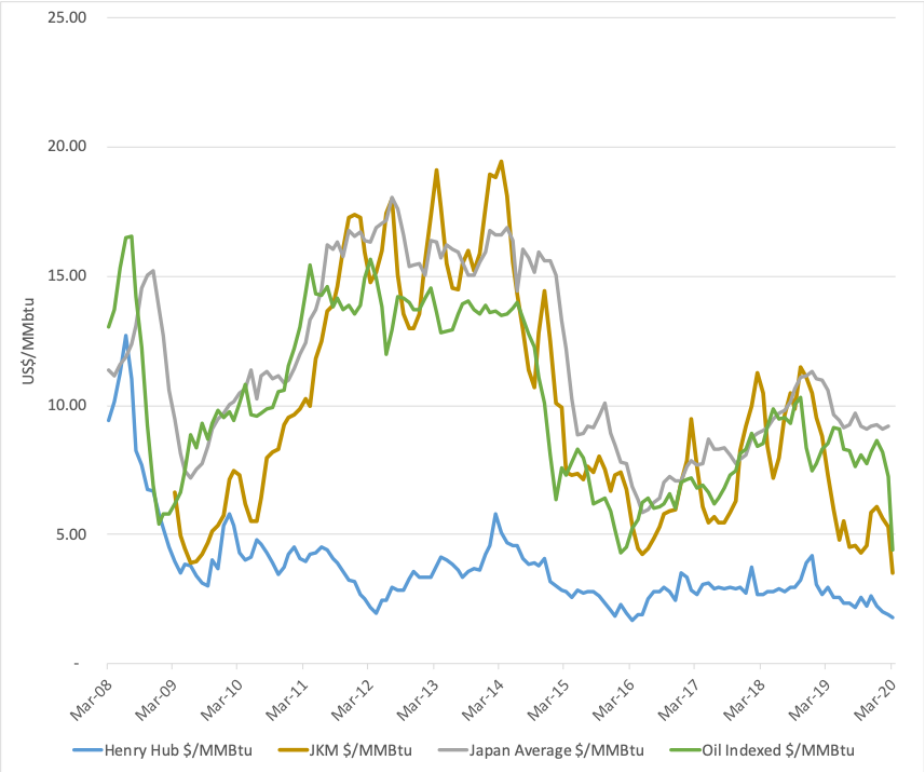
Finally, there is a new concern: that of peak gas. Whilst this is expected to occur later than peak oil and could be beyond 2040 (Figure 1), it could also be reached much earlier (Figure 3), within the production horizon of any new LNG project. Should demand decline faster than production capacity, the market could face a prolonged period of depressed prices, threatening project economics whether oil or gas indexed, particularly if countries with extensive gas reserves, such as Qatar, Russia, Australia and potentially Iran, seek to maximize production ahead of the decline. In such circumstances the level of debt for any new project would be much reduced, if available at all.

[29] Corbeau, A-S. (2019). 'Recent Evolution of European and Asian prices and implications for the LNG market', *OIES Forum* 119.

[30] In oil-indexed pricing, the LNG price is determined from the price of crude oil (Brent, or more often the Japan Customs Clearance), multiplied by a factor ('A' or the 'slope') to convert from US$/bbl of crude oil to US$/ MMBtu of LNG plus a constant 'B' usually representing the shipping cost. For calorific equivalent the slope would be 17.2%. Most early LNG contracts had a slope of 14% to 15%, but this varied, including at times S curves, and has reduced to 10% to 12% in recent years. This calculation assumes a slope of 12%, $20/bbl oil price and $0.60/MMBtu freight.

[31] Lenders will stress the finance against a sustained low price, constant real, over the repayment period, and also against more severe price dips over a shorter term of perhaps two or three years.

Figure 11: Asian LNG prices



Source: Platts[32]

5.2 Relevance of the index

Lenders are also concerned with the appropriateness of any index. Current market turmoil has highlighted the challenges of indexing LNG against oil, which has little real relevance to the buyers markets.[33] Whilst an LNG market index should better reflect the buyers economics than oil, it does not represent, and may still deviate from, any buyer's actual economics of sales of gas into their local market. For example, if LNG prices are high due to demand in one Asian market, but another market is less buoyant, that buyer may be unable to pass through such high prices. Similarly, a step increase in spot pricing may have to be absorbed by buyers before it can be passed through to consumers. These risks should diminish as more buyers switch to LNG market pricing, even more so if and when the Asian markets are further liberalized. For these reasons, buyers may choose to make the conversion gradually. In any event, lenders are likely to resist 100 per cent JKM escalation in the near term and projects needing finance may have to live with hybrid pricing.

5.3 Demand risk

There are a number of reasons why the level of future demand for LNG during the transition to open markets may be more uncertain now than previously. In the short term, the process of recovery from COVID-19 is a new uncertainty, but it may have longer term implications in its impact on human behaviour, such as the response to home working and climate change.[34] New LNG markets may be more uncertain than the established markets of Japan, Korea and Taiwan. Perhaps most significantly, future government energy policies and consumer attitudes in response to climate change and

[32] Oil Indexed data from Platts Brent times slope of 12% plus $0.60/MMBtu

[33] and exposes the project to double price risk: directly to oil prices and indirectly to gas prices in that, if too far out of the market, buyers may attempt to renegotiate or even default.

[34] This point was made by Spencer Dale, Chief Economist, in BP's Energy Outlook 2020.

atmospheric pollution are hard to predict.[35] Diversity is increasing as new markets open and, with increasing competition, price will drive convergence of supply and demand. But that does not remove the risk to new project investment; that demand and hence market prices when the plant is up and running may fall far short of that projected at loan signing. Irrespective of any long-term offtake agreements, project finance will not be available if lenders cannot see reliable underlying demand at prices sufficient to service the debt.

5.4 Precedence

The sheer size of LNG liquefaction projects has necessitated an extent of institutionalization. Raising in excess of $10 billion in debt finance for a project requires a significant percentage, if not most, of the commercial banks active in energy project finance together with several leading export credit agencies.[36] This involves many individuals, not all expert in gas and LNG markets, who rely both on industry consultants and deal precedents. Precedent can and is frequently broken, but it remains a resistance to change. Acceptance of pricing on a gas market index in Asia deviates from a long history of oil indexation, but the precedent is already broken with European gas market indexation and, as depth and transparency increases, precedence itself should not prevent gradual acceptance of an Asian gas market index.

Absence of long-term offtake contracts is more challenging, given extensive precedents in project finance across a range of industries for contracts with creditworthy buyers for the full offtake from the project, or at least for volumes sufficient to repay debt under a range of sensitivities (Appendix 4). The exception is oil and gas reserve based lending which often does not require offtake contracts, but this is a somewhat different market with shorter tenors, different dynamics, and much greater market liquidity (Appendix 4, Section 1).

Precedence creates resistance to change but can be overcome if the case is strong enough. It helps if all other aspects of the credit assessment are sound, and leadership from key lenders who fully understand the strengths of the project can also help.

5.5 The possible outcome

Taking the two questions separately:

5.5.1 Will lenders accept Asian Hub Gas Price Indexation?

As buyers and sellers progressively move towards gas price indexation, lenders can be expected to accept an element of Asian hub gas price indexation provided: (a) they can be convinced of the depth and transparency of the index; (b) they can be assured that the LNG can be sold into that market at the resultant contract price;[37] and, (c) their assessment of future gas prices under a low case scenario provides sufficient debt capacity. (This last caveat applies whether oil or gas price indexation). This acceptance will likely come in stages, with initially acceptance of a percentage of JKM indexation amongst the total revenue. For some projects, this may be a lower percentage than buyers and sellers would otherwise agree.

5.5.2 Will lenders still require long-term SPAs?

As yet no new liquefaction project has been project financed without the majority of offtake under long-term contract. In the face of pressure from buyers and developers, lenders could probably accept some reduction in SPA tenor, say from 20 years to 15 or even 10 years. ECAs 'tied' loan terms (see Appendix

[35] Rogers shows Asian LNG demand of 450 Bcm/a low case in 2030 and 550 Bcm/a high case – a range of 100 Bcm/a – and adds '.. the unpredictability of government energy mix policies (including issues related to CO_2 and particulate pollution and nuclear phase-out/restart) and of the extent to which domestic production decline will necessitate LNG imports, makes projections highly uncertain'. Rogers, H. (2020). LNG demand in Asia – are growth trends likely to continue'. LNG in Transition; *OIES Forum* 119. More recently, see Figure 3 herein, range of gas demand from BP's Energy Outlook 2020.

[36] PNG LNG was financed by 6 ECAs and 17 banks, and Ichthys LNG by 8 ECAs and 33 banks.

[37] Lenders were inclined to assume this for oil-indexed contracts when all such contracts were oil-linked and buyers were assumed able to pass on prices to the market. Asian hub indexation may lead them to re-assess this risk.

2) are limited to no longer than 10 years from completion, and banks rarely lend longer. Debt capacity would reduce a bit as lenders like to see a 'tail' of contracted revenues beyond loan maturity, but this tail does not add a lot to debt capacity. As the industry transitions progressively towards open, deep and free gas markets in Asia, three scenarios could be considered:

Scenario 1: Retention of the contractual model

Under this scenario, lenders stick to the conventional project finance requirement for long-term volume commitments from strong buyers in, or having assured access to, the intended gas market, sufficient to service debt in full under a range of sensitivities. Lenders may resist any deviation from this, partly out of precedence but more so with concern for the developing risk profile under which a cyclical market leads to periods of very low prices and liquefaction margins. Under this scenario, overcapacity could result for a number of reasons including: (a) over-building, whether through the optimism of developers keen to get their project off the ground with portfolio buyers, or otherwise; (b) government policy changes, and (c) uncertainties in climate change policies or technology. Lenders will also note that domestic gas markets across Asia remain a long way from deep open traded markets.

This does not necessarily require all the output to be under long-term contract, as debt can usually be serviced from something less. But to get an acceptable level of debt finance, particularly on a greenfield project, will likely require a significant majority, if not all, of the offtake over loan life to be contracted before loan disbursement.

This existing model is likely to attract the widest range of lenders including commercial banks, supplier-country export credit agencies, buyer country agencies and banks, and potentially debt capital markets.

In this, as other scenarios, lenders are likely to gradually accept gas market price indices provided they can be convinced of their depth and transparency.

Scenario 2: Aggregation

For the larger players, market risks can be mitigated by aggregation to diversify risks. There are already several of the majors acting as portfolio buyers, contracting to take the offtake from projects into their overall portfolio. Lenders to the project are invited to rely on the portfolio buyer to lift LNG without necessarily knowing which market will be the end user. Their response has been to seek some analysis of the intended or likely end user markets, and of the portfolio buyer's access to those markets, but otherwise are generally receptive to this approach. These portfolio players may choose to include a portion of the offtake at JKM or other gas price index, and to sign long-term contracts to buy LNG before having any re-sale contracts in place. While a potentially financeable model, the risk remains of a portfolio buyer being unable to place the LNG in the intended market. Lenders will evaluate each project on its exposure to this risk, with the possibility that they will require additional support.

In the US, LNG developers typically use bank project finance for project development, refinancing into the bond markets at completion. An advantage of this is that the debt can be repackaged to give lenders to any new project a mix of existing and new sales contracts; so again, lenders can be offered a diverse mix of offtake contracts including a portion of JKM indexed.

In either case the scope for aggregation as a risk mitigant, whether at the project level or across more than one project, could benefit the larger players.

Scenario 3: A market-based approach

If Asia were to move more rapidly towards freely traded gas and LNG markets as in North America and Europe, developers might be willing to reach FID on liquefaction projects without contractual offtake. But they would presumably require:

- assured physical access to the gas markets such as through contractual rights to import capacity and/or open access legislation providing assured access;

- open market conditions in each target market supported by clear government legislation and policy; and
- ideally a physical hub around which there is a deeply traded spot market.

These conditions do not exist in any major Asian LNG importing country today and the challenges to their development are higher in Asia than the US or Europe. Should the market develop to the extent that project developers are happy to commit significant capital without long-term offtake agreements, it may take another development, that of deep and freely traded finance markets where loans can be traded and lenders can assume there is a refinance exit, before lenders would accept the same risk profile. The North American project bond market comes closest to this, but for projects with long-term offtake commitments. Perhaps for the first time, the debt markets could fail to provide finance on terms that meet developers' needs. More likely, however, developers and buyers will themselves still require long-term contracts for at least a substantial portion and, in many cases lenders will accommodate some flexibility to accept a greater degree of contract flexibility.

5.6 The impact of climate change

Growing pressure on governments and industry to speed up decarbonization adds a new layer of uncertainty, as changes in government policies could substantially increase or decrease gas demand, and governments can be hard to predict.

There is also the risk of lenders yielding to public or activist pressure to a greater extent than the industry. Government agencies, and commercial banks with a retail network, are sensitive to their public profile and increasingly questioning the appropriate response to climate change pressures. To date this has impacted loans to the coal industry, but three factors could impact gas.

First, there is growing, and already quite intense, pressure on European institutions to cease financing hydrocarbons from fracking. BNP Paribas, France's largest bank, has already ceased lending to projects involving fracking[38] and others could follow. This could impact North American projects where, as elsewhere, much of the project finance expertise and capacity is with the European banks. It will not prevent these projects getting finance from the US capital markets but may increase financing costs due to the 'negative carry' (see Appendix 1, Section 4: Bond Markets).

Second, pressure is building, particularly on European banks and ECAs to cease funding hydrocarbon projects. At this stage banks and ECAs are continuing to support the LNG industry, but climate change pressure is increasing.

Third, the industry and its lenders are increasingly having to document and justify their environmental efforts. This will include focus on 'well to burner' emissions, good industry practice regarding flaring and losses, demonstration that the project is climate change positive such as by replacing coal with gas (potentially more challenging for sales into Europe than Asia) and perhaps by carbon offset arrangements. Amongst other pressures, most banks active in project finance have signed the Equator Principles[39] which set out policies of good practice in respect of environmental and social risks that signatory banks have agreed to adhere to. Version 4 of the principles came into force in October 2020, extending the applicability to developed as well as undeveloped countries, and further detailing the approach to climate change. This includes agreement to analyze alternatives to the project that might have a lesser greenhouse gas impact, and a justification for the chosen solution.

The industry has a strong case to make that gas and LNG are important to global energy supplies and can be consistent with limits to global warming. Nevertheless, developers needing project finance will need to be aware of potential lender constraints related to climate change. This is likely to include more environmental vetting and, particularly if pressure spreads beyond European lenders, to restrictions on the availability of finance.

[38] https://group.bnpparibas/uploads/file/csr_sector_policy_unconventional_oil_and_gas_19_12_2017_v_standardized.pdf
[39] https://equator-principles.com

6. Conclusions

Perhaps for the first time, project finance may struggle to adapt to changes in the LNG industry and may not always be able to finance future projects on the commercial terms required to meet developer and buyer requirements. The key challenges, and their likely impact on LNG lenders (in bold), are:

1 The industry is in transition from the historic 'tramline' model with its long-term commitments from buyers with dominant positions in their local gas markets, towards a global traded market where prices are determined by the market. This transition is changing the structure and priorities of the industry. Oil indexation and 'Henry Hub plus' price terms seem less appropriate in a traded market environment and may be replaced by local gas market prices in Asia, as in Europe. More LNG is being traded on spot and short-term contracts and, as markets deepen, the need for long term offtake commitments becomes less obvious.

A change to gas market pricing such as JKM for sales into Asia will be accepted over time, as it has been in Europe, but not without some resistance. There is no single Asian gas market, individual gas markets are less liberalized than in North West Europe, and JKM is as yet thinly traded. The industry itself may choose to adopt JKM indexation progressively over time, but a more immediate adoption may not be supported by their lenders.

Project development with lower or no long-term volume commitment would be more problematic. Project finance in any comparable industry requires long-term volume commitment sufficient to fully repay the debt. For LNG, some accommodation of shorter terms may be considered below the traditional 20 years, but the need for sufficient contracted volume to repay debt in full under a range of scenarios is unlikely to be relaxed.

2 There is much uncertainty in the level of future LNG demand – in how fast and in what way global economies will come out from the COVID crisis, and longer term in how governments and markets will respond to climate change; such that LNG demand could be significantly higher, or lower, than expected. Under the more extreme downside scenarios, the next wave of investment could be followed by a sustained period of overcapacity and depressed prices.

This uncertainty adds more weight to the requirement for long-term offtake commitments from strong buyers with assured market access. It also favours the stronger players who either do not need project finance or who are more able to attract it.

3 Much of the next wave of LNG investment could come from North America where supply is abundant and all in cost is relatively low. But having a domestic market at source provides an alternative use for the gas such that, when built, a North American LNG project may not be able to compete in cash costs with international projects selling into Asia. Furthermore, as markets deepen, 'Henry Hub plus' pricing is likely to look less attractive to buyers.

Responses to this challenge are likely to be several, as developers seek various ways to get their project to FID, such as: offering a netback price to gas sellers; offering buyers a cocktail of indices including a portion of HH+; portfolio players taking the price risk between US and end user markets; offering buyers a share in the midstream and upstream projects and, no doubt, others.

4 Climate change adds a further challenge requiring lenders to demonstrate sound environment policies. European lenders have ceased funding coal and are under pressure from some quarters to cease all fossil fuel lending.

Developers should expect further environmental scrutiny from lenders, including the need to demonstrate the project's climate change credentials. Evidence that the project

helps to replace coal with gas burning would be an example. At present the pressure is largely on European lending institutions but could spread.

On the positive side, many of the market risks may be mitigated by aggregation of projects and/or revenues. Alternatives source of debt will be found if needed, such as buyer or buyer-country finance and/or the bond market; and many of the larger players do not need project finance. These options may present a competitive advantage to larger portfolio players and perhaps for expansion projects.

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Appendix 1: Lender Markets

This appendix sets out the different potential lenders to an LNG project.

1. Commercial banks

Commercial banks pioneered project finance and led its application to the LNG industry. In 1987, Woodside raised $1.65 billion entirely from 58 banks, for its share of the first North West Shelf LNG project. For those banks that had built the analytical capability, LNG finance became popular for their client relationships, their size and profile, and their strong credit structure and low probability of default. This remains the case, but the size of many LNG projects has grown to outstrip bank market capacity and large multi-billion dollar projects require other funding sources to complement the banks.

The banks are also impacted by pressures on their balance sheets and regulatory controls. Banks raise much of their capital from retail and commercial deposits which are withdrawable on demand. Using these to fund long-term loans exposes the bank to a liquidity risk whereby, in the event of a banking crisis, there could be insufficient free capital to meet sudden withdrawal demands. Regulators necessarily focus on the credit strength and liquidity of the banks loan portfolios, and post the 2007-2009 financial crisis, the Basel Committee on Banking Supervision established an internationally agreed set of measures to strengthen the regulation, supervision and management of banks.[40] Many banks struggled to meet regulators newly increased demands for capital adequacy. Project finance was hardest hit due to its long tenor and limited market for trading project finance loans, and some banks exited the project finance business. Since then, liquidity in the bank market has improved, but also the regulations have tightened. Current guidelines are set out in the Basel III regulatory framework of 2017[41] which bank regulators of the 45 member countries are committed to implement. They include:

Minimum capital requirements

Banks must maintain common equity capital of at least seven per cent of risk-weighted assets, thus limiting the leverage and risk to the bank's balance sheet. There is extensive guidance on the calculation of risk-weighted assets, taking into account credit risk, market risk and operational risk. Credit risk is assessed by looking at the risk of default and expected loss given default. Project finance gets treated as higher risk by being long-term, and often because of the risk of default, but offset somewhat by a, usually, low loss given default.

Liquidity

Banks are required to meet a Liquidity Coverage Ratio ensuring ability to withstand a 30 day stress test, and a Net Stable Funding Ratio designed to address the risks of borrowing short and lending long.

The combination of these regulations puts an additional cost on project finance and encourages banks to find ways to trade their loan portfolio so that they can manage their assets and continue to generate new business. For example, there is an increased interest in initial bank lending with the expectation of refinance into the debt capital markets (see below), though this has been slow to develop.

2. Export Credit Agencies

Export Credit Agencies (ECAs) were initially used in project finance for political risk cover whereby they provided guarantees, callable in the event of loss due to a political event. As the size of loans grew, they became more important simply for capacity, providing straight loans in parallel with the banks. In 2009, PNG LNG raised $10.5 billion of third-party debt in the then biggest project finance ever, including $8.3 billion from six ECAs.[42] It could not have been done without them. Recognizing the importance of

[40] Bank for International Settlements – bis.org
[41] https://www.bis.org/bcbs/basel3.htm
[42] ExxonMobil presentation at US Exim Conference, March 11, 2010. https://www.exim.gov/sites/default/files/events/annual-conference-2010/PNGLNGProjectFinance.pdf

ECAs, project financings are now usually negotiated first with the ECAs, bringing commercial banks in once an agreed term sheet[43] is in place.

ECAs lend under two main programs. Under classic 'tied' export finance, world trade rules allow countries to provide finance for equipment and services exports under common consensus rules regarding tenor and pricing. ECAs in LNG buyer countries can also provide 'untied' finance to the project, at the request of the LNG buyers or sponsors.

3. Multilateral Agencies

Multilateral Agencies (MLAs) such as the World Bank and its affiliate the International Finance Corporation (IFC), Asian Development Bank, African Development Bank, and others act as a 'lender of last resort' lending to projects that they deem of particular benefit to their member countries, where finance cannot otherwise be raised. They may advance equity and/or a direct loan ('A Loans'), and arrange a larger loan which is funded by commercial banks ('B Loans'). IFC was involved in Yemen LNG and Peru LNG, but overall the MLAs have been only minor lenders to LNG.

4. Debt Capital Markets

LNG projects have long hoped to tap the deep US bond markets which provide attractive assets for pension funds, insurance companies and other long-term investors, have enormous capacity and are the main source of long-term debt for investment grade corporates. There is also a high yield market for non-investment grade credits, but as the name implies, this is significantly more expensive. So the challenge is to get investment grade rating (at least Baa3 from Moody's, BBB- from Standard and Poor's).

Most international projects have not sought, or not succeeded, to access this market mainly because they and the rating agencies tend to view emerging market risk as non-investment grade.[44] But it has been popular in the US where Cheniere has issued bonds for Sabine Pass LNG and Corpus Christ LNG, as has Dominion for Cove Point LNG. Internationally, RasGas in Qatar has raised several bond financings, and in 2009 Peru LNG secured additional funding from a bond issue.

The bond markets include publicly traded and privately traded debt. Both are regulated by the relevant exchanges on which they are quoted and are supported by a credit assessment from one or more (and at least two in the case of publicly traded debt) of the main debt rating agencies – principally Standard and Poor's (S&P), Moody's, and Fitch. These ratings are a key determinate of whether the bond can be sold and at what price. There are just over 20 ratings steps ('notches') from AAA (S&P) or Aaa (Moody's) for the strongest credits, through to D (S&P) for a loan in default. Importantly, the public debt markets require an investment grade rating from at least two agencies. S&P[45] and Moody's[46] publish their ratings criteria for project finance. Each agency's approach differs somewhat from each other and from commercial banks, but in general:

- much of the key credit criteria are very similar between banks and rating agencies, including the competitiveness of the project, the capability, strength and commitment of the project sponsors, the sensitivity to commodity prices, counterparty risks and country risks.
- Rating agencies and bond investors are necessarily more focused on the timeliness of repayment, as traded debt generally has fixed repayment schedules whereas banks can often

[43] Loan agreements are normally negotiated in a two-stage process. The first stage leads to a Term Sheet setting out the principal terms for agreement, prior to documenting these in the detailed loan agreement. (Term Sheets used to cover just principal commercial terms in a few pages, but now more often run to well over 100 pages to include anything that could be the subject of disagreement).

[44] Peru LNG is an exception which successfully refinanced debt with a 144a bond issue.

[45] Standard & Poor's Project Finance Ratings Criteria Reference Guide. September 16, 2014. https://www.spratings.com/documents/20184/86990/SPRS_Project%2BFinance%2BRatings%2BCriteria%2BReference%2BGuide_FINAL/cdfde690-57d1-4ff4-a87f-986527603c22

[46] Generic Project Finance Methodology, Moody's Investor Services. November 27, 2019 https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_1194215

tolerate some flexibility in timeliness, provided it is anticipated in the loan agreement. For LNG projects this can require higher levels of cash held in reserve in a debt service reserve account.

- Banks can, at times, be more accommodating of completion risk and country risk. For example, in the PNG LNG project, banks were able to distinguish between the country risk of debt to PNG (rated single B) to the risks to the LNG project which was unrated but would generate strong foreign exchange to the country and considered close to investment grade.

Once signed, funds under a project bond are advanced in one lump sum, rather than over time as construction progresses. Referred to as 'negative carry' this imposes an additional interest cost on funds held in advance of need. For these reasons, it is more common for the initial funding to be provided by banks with the borrower having the option to refinance subsequently (usually after completion) in the bond markets.

5. Buyer Country Institutions

In recent years, ECAs and state-owned banks from the main buyer countries, especially China, Japan and Korea, have contributed significant levels of funding for projects supplying LNG to their countries.[47] These countries have extensive finance available and can be expected to apply it if needed to any LNG project deemed important to that country.

6. Sponsor Co-Lending

A few of the larger LNG developers do not require external debt finance, preferring to raise their share of the debt more cheaply at the corporate level. For example, Exxon and Total co-lent $3.75 billion and $4 billion respectively in the PNG and Ichthys projects, alongside other lenders. These sponsor loans share identical terms including pricing, recourse, repayment, and so on, with the only exception being that they have more limited voting rights. This has provided useful additional capacity for many projects, though the primary purpose was sponsor preference.

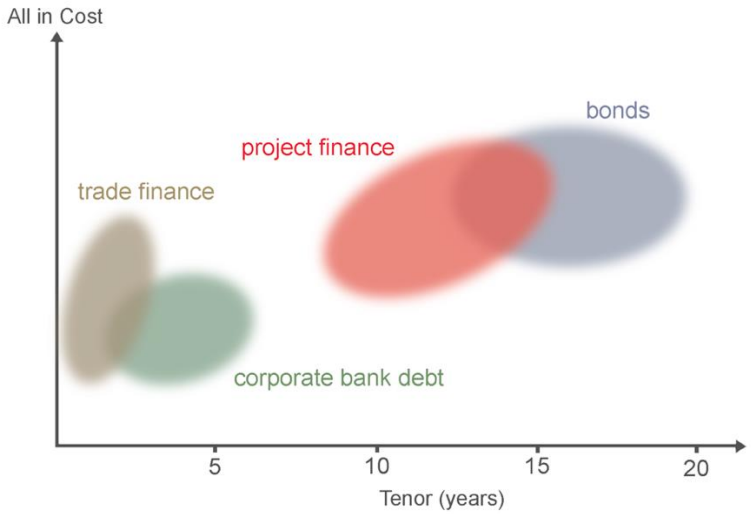
[47] PNG LNG and Yamal LNG

Appendix 2: Reasons for Project Finance

The most common reasons for using project finance are:

- Availability of long-term debt. Many LNG projects have at least one sponsor (often but not necessarily a host government) that is unable to fund their share of the project from corporate sources at attractive rates, if at all. Bank debt to corporates is usually short and medium term, leaving the bond markets as the main source of long-term debt, but this becomes very expensive in the absence of an investment grade rating. Project finance may be the only, or the more attractive, source of finance (Figure 12).

Figure 12: Cost of finance versus tenor



Source: Author

Even where only a minority of the ownership requires project finance, the stronger sponsors wish to ensure that all partners will be able to fund their share through to completion, and that they do not have to underwrite weaker partners or take a disproportionate share of the funding risk relative to their equity share. The simplest way to achieve this is a limited recourse project finance for the project as a whole.

- Validation of the soundness of the venture. In the past, companies have often been able to account for projects on a net equity basis such that the debt does not appear on the parent company's balance sheet. With tighter accounting rules this is generally not possible, but footnotes to the accounts that the debt is limited recourse are a signal to investors and lenders to the parent company that the project risks are likely to be modest and that, in the extreme, lenders will take some of the risk.

- Risk sharing. Ostensibly this is a major advantage of project finance as, post-completion, lenders recourse is limited to the project, not its sponsors. If the project fails or underperforms, lenders share in the risk and in some circumstances may not get repaid in full. However, project finance is structured such that equity owners still take much of the risk on a first loss basis. Revenues have to deteriorate substantially, reducing equity return, before loan repayment is impaired to the extent that full repayment is not achieved. For most LNG projects, this has never happened.

- Cash flow matching. Whilst lenders will expect to be repaid under all likely circumstances, it is not uncommon for repayments to vary year by year according to the available cash.

- Infrastructure finance. Of growing interest is the use of project finance to facilitate access to low cost infrastructure equity funding. There is a huge amount of funding from pension funds and insurance companies seeking attractive, long term, low risk, investment opportunities. Infrastructure projects which are contractually structured to provide a secure cash flow, often

tied to an index of inflation to give a constant real return, provide ideal investments. This market has funded many of the public-private partnerships popular with governments seeking privatization opportunities. Energy companies have also tapped this market, selling off some of their infrastructure such as ships and pipelines with capacity agreements to retain continued usage access. More recently, US LNG projects have tapped this market, bringing in an attractive mix of project finance and infrastructure equity funding.

Appendix 3: Lenders Risk Analysis and Due Diligence

Risk analysis

Taking the construction and operational phases separately:

Construction phase

In most LNG projects, lenders require several guarantees of the debt from credit-worthy sponsors through to completion of the project and satisfaction of a lender-defined completion test (following successful completion of these completion tests sponsors guarantees fall away). This simplifies lenders credit assessment, reduces the need for a single EPC contract with extensive guarantees and liquidated damages, and keeps the financing costs down. More recently, several US export projects have been financed without completion guarantees, benefiting from little co-completion risk of other projects (such as gas supply and many offsites), ability to obtain an EPC contract for the total works, and the reliability of US construction.

With or without completion guarantees, lenders will analyze the construction risk to determine what could go wrong and how it might affect their credit, and will want to ensure ability to survive a reasonably worst case cost overrun and delay.

Operating phase

Once the lenders completion test has been met (including a period of several months of operation beyond acceptance), the principal risks are market and feedstock related. These, and other risks, are analyzed by extensive modelling of project cash flows to determine in each case:

The loan life cover ratio (LLCR)

This is the net present value of future cash flows over remaining loan life discounted to the date of completion, divided by peak debt at completion. Cash flows are discounted at the projected cost of debt so that, with an LLCR of 1.0, the project would just repay debt within term. Many LNG projects have had a projected LLCR comfortably over 2 in the base case, with downside sensitivities all over 1.

The breakeven oil (or gas) price

This is the price (usually constant real) that would just repay debt within loan term (that is, at an LLCR of 1.0). This provides a simple, clear indication of the price risk that lenders are exposed to.

The debt service cover ratio (DSCR)

Whereas LLCR and breakeven oil price demonstrate ability to repay debt within term, the DSCR measures free cash available divided by debt service (interest and scheduled repayment) year by year. Ability to repay year by year is further supported by a mandatory debt service account holding cash sufficient to meet several months debt service in the event of interruptions to cash flow.

The credit approval process

The process of risk assessment differs somewhat between different institutions. Commercial banks have internal guidelines but are relatively pragmatic in their approach, and the process is led by the 'front office' marketing and structuring team whose role is to build profitable deals and client relationships. Their recommendation is presented to a credit department, for either committee approval or a sequence of individual approvals. The credit department reports to the most senior level of the bank and is responsible for setting and enforcing bank wide credit standards. Nevertheless, appeals can be made, noting any commercial, relationship or market positioning arguments for doing the deal.

Export credit agencies have different priorities as their primary role is to support exporters – equipment suppliers – rather than the project itself. They tend to be more focused on guidelines and precedents, and on the social and environmental impact of the project. Nevertheless (perhaps because most large projects require bank and ECA finance) the two have somewhat converged in their approach and now are very similar in their credit assessment.

The debt capital markets differ in that the loan needs to be sold (and re-sold) to a wide range of investors who do not have the time or inclination to assess the credit. Hence, they rely on the credit score given by one or usually two of the leading credit agencies. These agencies need to apply clear, transparent criteria to support their independent credit opinion. Again, however, the key principles of their credit analysis are similar to the banks and ECAs (and is further described in Appendix 1).

Due diligence

The lenders due diligence is primarily a verification process of checking assumptions. It includes independent reviews of markets and market risk, technical performance and risks, environmental and social compliance and risks, security risks, and extensive legal review of the obligations and enforceability of the loan agreement and all relevant commercial agreements including compliance with local and international laws. The process involves the hiring of independent consultants in each of these areas, including local and international legal counsel. There are generally two key stages in the process, before and after participant lenders are asked to commit to lend subject to documentation. It has become the practice to seek these lender commitments on a detailed term sheet, with most of the due diligence in place apart from some of the more detailed legal review.

Appendix 4: Comparable Energy Industries

In considering how lenders might react to this changing environment, it is worth looking at their response to other industries.

1. Upstream oil and gas

Lending to upstream oil and gas development has a long history in the US, and remains somewhat independent of, and different from, other project finance markets. Referred to as reserve based lending, many banks manage it with specialist teams separate from project finance. In its early configuration, and to a large extent still today in the US, bank loans are advanced only against proved, producing reserves.[48] The loans have full recourse to the borrowers and are secured on the reserves, usually on a portfolio of fields. Loan tenors are modest - typically three to five years - and loan controls require the maintenance at all times of a borrowing base cover ratio calculated from the net present value of future cash flows, but excluding reserves beyond a percentage (in the early days 50 per cent but now dependent on a risk assessment and generally higher) of proved. Many companies arranged high yield bonds ranking behind the bank debt, for pre-completion finance and to top up their debt.

Criteria have relaxed somewhat since, but North American reserve-based lending remains essentially medium rather than long-term, and predominantly corporate lending against existing oil and gas production. Lenders are exposed to reserve, production and oil price risk, but mitigated by strong economics, the underlying value of reserves (often including fields beyond the borrowing base), and usually by a mandatory degree of oil price hedging. Offtake contracts are not deemed necessary given the exceptionally deep and open market for crude oil and gas in the US.

When oil and gas developments began in the North Sea, American and British banks started to adapt reserve-based lending to this different market, taking tenors out to around 10 years to accommodate the longer life projects and lack of deep refinancing market. Individual projects were larger with significant development risk, but by the time of development approval, with reserves proved up and substantial sunk costs, the pre-tax economics could be exceptionally strong. Progressive taxation took a large share of the economic rent – up to 81 per cent[49] – and risk, which substantially mitigated price and other risks. Consequently, most loans had completion guarantees, but took reserve, production and price risk thereafter. Offtake contracts were required for gas production, but not always for oil.[50]

2. Pipelines

A number of oil and gas pipelines have been project financed and have some risk factors common to LNG. They are generally regarded as core infrastructure and financed with full long-term throughput agreements, typically providing a constant real tariff such that, barring default, lenders are protected from volume and price risk.

3. Power generation

Power generation has been the largest user of project finance over the years, representing slightly over half of all project finance. The typical model is for either long-term contractual fuel supply and power purchase agreements, or regulatory tariffs, that in either case provides a secure revenue stream, protecting lenders from volume and price risk. There are some notable exceptions; in the US and later in the UK and EU following deregulation, when lenders took open market risk. Both cases led to

[48] Fox, J., Gonsoulin, D. and Price, K. (2014). 'Reserve-based finance, a tale of two markets'. *Oil & Gas Financial Journal*. https://bracewell.com/sites/default/files/assets/OGFJ%20April%202014.pdf

[49] Seely, A. (2015). 'Taxation of North Sea oil'. Research Briefing. https://commonslibrary.parliament.uk/research-briefings/sn00341/

[50] Offtake contracts are required for oil production from projects in emerging markets but more as a means to securitize offshore dollar revenues.

substantial loan losses as capacity surpluses led to very low spark spreads and inability to service debt. Project finance banks have since generally declined to finance 'merchant risk' in power projects.

4. Petrochemicals

Unlike power generation, base petrochemical plant such as ethylene crackers are usually financed with lenders taking full price risk, despite the highly cyclical price swings over the capital investment cycle. The typical model, prevalent in the Gulf Cooperation Council (GCC) region[51] but also more widely used, was for full completion guarantees and full long-term feedstock supply and product offtake agreements providing volume assurance but at market prices. Lenders looked at the competitiveness of the project and its ability to survive through the bottom of a cycle, and on this basis were often able to finance 65 – 70 per cent of the total project cost.

[51] United Arab Emirates, Saudi Arabia, Qatar, Oman, Kuwait and Bahrain.

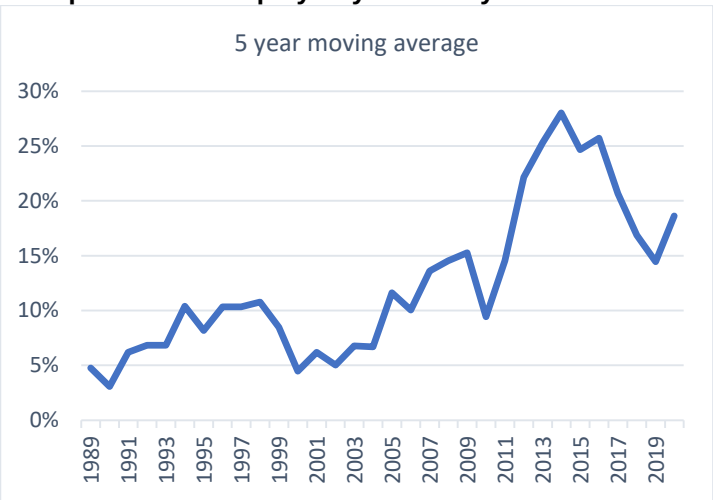
Appendix 5: Market Players

LNG liquefaction has been dominated historically by the major international oil, and state oil, companies as a means to monetize gas reserves. But the business is long term and ties up large amounts of capital in the infrastructure, and several of the majors did not initially seek out LNG investment (arguably only Shell took an early interest to develop it as a major business line though ExxonMobil, Total and BP have become major players).

Three other groups have entered, or may enter, the business:

i. **Buyers** have frequently taken a minority equity position in the liquefaction projects, whether for information, increased security of supply, and/or price mitigation. The extent of this seems to have grown – from an average of 5 to 10 per cent in the early years to around 20 per cent since 2010 (Figure 13).

Figure 13: Share of LNG plant ownership by buyers or buyer-related entities



Source: Author based on public sources

As markets deregulate, buyers could see less need to invest upstream if they can buy freely at market prices. On the other hand, buyers could see the current weak market conditions leading to underinvestment, and at least some may see it as a means to encourage upstream investment and secure supplies at a predictable cost. (Incidentally in economic terms that would produce a cost profile not unlike that from existing North American projects which have a fixed component).

ii. **Infrastructure funds.** Long-term, low risk business is an ideal investment for pension and insurance funds. These funds have very low beta values,[52] typically below 0.1 compared with major oil companies of 1.0 to 1.2, so can accept a modest premium over fixed interest rates from low risk assets. The investment sums available are vast; much has gone into infrastructure business, but there is a shortage of suitable investments and fund managers are looking further afield. To date they have been nervous of emerging market risk which rules out most LNG projects aside from North America. This could change if they come to assess LNG export projects to be significantly lower risk than domestic or import projects, as they have been. A move away from long-term contracts would discourage this but, with creative risk management, the goal of using project finance and infrastructure funds to obtain lower cost finance may yet be achievable.

[52] The beta (β) of a stock is a measure of its market-related volatility relative to the entire market. A stock with β=1 has the same volatility as the market, and one with β>1 is more volatile than the market. β does not measure volatility that is uncorrelated to the market, on the assumption that investors can diversify away uncorrelated risk.

iii. **Traders** form a central role in the oil markets, helping to create liquidity and access to forward markets. Traditionally running 'asset light', they have over recent years acquired some infrastructure, including terminals, storage and refineries, to support these activities. They are becoming active in LNG trading but, to date, have made little or no investment in LNG liquefaction.