WILL LONG-TERM OFFTAKE CONTINUE TO DRIVE PROJECT FUNDING?

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ABSTRACT

As the LNG market evolves customers are urging project sponsors to accept shorter term contracts to underpin lending to LNG projects. We look at whether this is feasible and show that the main appeal of LNG projects has been the use of long term take-or-pay contracts or tolling agreements with investment grade counterparties.

Stress-tested to break even at low gas prices they allow for loan payback across the 14-year horizons typical for LNG project finance, thereby attracting billions of dollars in funding. In many instances this funding has been provided at low pricing compared to other industries. For example, commercial banks provided around $18 billion of funding to three US projects in 2015 at attractive margins.

Project sponsors and their advisors have made changes to the structure of project financings over the last two decades in order to overcome new challenges. It remains to be seen how extensively project financings will reflect the move in the overall LNG market towards shorter-term contracts. But with the industry undergoing a fundamental shift, this is not the only change that will face potential lenders to multi-billion dollar liquefaction schemes.
Securing funding for multi-billion dollar LNG projects depends heavily on the integrity of long-term offtake or tolling contracts. Without take-or-pay contracts, banks and other lenders, such as export credit agencies (ECAs), would be unlikely to provide funding in such large quantities because they would be exposed to volume risk. In each LNG project, institutional exposure can be as much as hundreds of millions of dollars and in some isolated cases it is even billions. In 2014, for example, the Japan Bank for International Cooperation (JBIC) provided Freeport LNG’s first train with $2.6 billion and the Cameron LNG project with $2.5 billion.

When companies from a bank’s host country are offtakers/tolling capacity holders, plus equity partners and construction contractors, the impetus for lending can be even stronger. For example, in 2014 Japanese banks provided over $5 billion or 43% of the total commercial bank lending to LNG projects and the bulk of this went to fund two US liquefaction projects which feature extensive Japanese offtake.

LNG project financing started to take off in the mid-1990s with the financings of Qatari and Omani LNG projects, but jumped up a notch in 2004-05, when larger Qatari deals came to market. Records were set by Qatargas 2 and RasGas 2/3 for size and debt load. These were broken again by Papua New Guinea’s PNG LNG which raised $13 billion in debt in 2009 and Australia’s Ichthys LNG which raised $20 billion of debt in 2012. Ichthys remains the world’s largest project financing deal, although it should be noted that the debt included $4 billion in loans from the shareholders.

Ranked by debt, LNG projects including Ichthys account for eight of the world’s top ten project financings over the last ten years (Figure 1 –Top Ten Project Finance deals). There are larger projects under construction, but some of these are not project financed, including Australia’s $55 billion, 15.6 MMT/y Gorgon LNG.
Funding via project finance structures for LNG projects has been provided at low pricing compared to other industries. The nearly $60 billion worth of LNG projects that have secured funding over the last ten years show an average contribution from commercial banks of around $2.2 billion per project, at an average price of around 174 basis points (bps) – in this assessment we have taken the midpoint of margin ranges – over the London Interbank Offered Rate (Libor). Large deals across other sectors such as oil refining, pipelines, petrochemicals, mining, metals, power and water show an average commercial bank contribution of $1.8 billion priced at 223 bps over Libor (see Figure 2, LNG Project Finance – Bank Debt and Pricing and Figure 3, Other Sectors Project Finance – Bank Debt and Pricing).
Assuring offtake through long-term contracts protects against volume risk and gives banks the security that loans will be paid off across the long-term horizons of 14 years that are typical in this sector. Loans can be of even longer duration and Freeport LNG’s train 1 loan spans out 22 years because ECAs are the dominant providers of funds and cover and they are comfortable with long-tenored lending.

Bank pricing for US LNG project financings have come down recently, as banks have remained liquid, and also become increasingly comfortable with the US model. US projects make up the bulk of LNG project financings concluded in 2014 and 2015.

Generally, aside from Cameron and Freeport train 1, the US financings that have been completed thus far for Sabine Pass trains 1-5, Freeport trains 1 and 2 and Corpus Christi trains 1 and 2 have used shorter tenored-financing of around seven years which can be further reduced by taking out the bank contributions via refinancing in the bond markets.

This is embraced by banks, because it lessens their risk – lending over longer horizons is seen as more risky. Of course, long term offtake or tolling contracts reduce that risk markedly, as explained, but it can never be zero. There is always the possibility, no matter how remote, that a project will fail.

LNG contracts allow pricing fluctuations and, while S-curves and other mechanisms offer protection against volatility particularly where there is a link to oil prices, there are typically reopeners for negotiations on the upside and downside. It is impossible to shield completely against pricing risk, but generally these projects are stress-tested to low prices, allowing them to ride out a number of commodity cycles during their producing lifespan. The breakeven volume of LNG required to service debt will typically be lower than the customers’ take-or-pay amount.

Banks will understandably resist any pressure to change this tried and tested structure. In order to allow financing based on shorter-term transactions, project costs would need to come down a lot (unlikely) or the LNG market would have to mature markedly. It would need to offer much greater liquidity, like the crude oil market, giving producers the ability to sell at index pricing and have this absorbed easily by the market.

**SHIFTING MARKET**

But there has been a recent shift from a sellers to buyers’ market, with downwards pressure on pricing – crude oil prices fell in January to below $28 per barrel for the first time since 2003, and Henry Hub slumped to $1.755 on December 17, 2015, which is the benchmark gas price’s lowest inflation-adjusted price in NYMEX trading history. Now calling the shots, buyers are negotiating for more flexibility and shorter contracts in those up for revision, and have managed, in some cases, to force changes to contracts already in place. Contracts have reduced in length by 8.5% year-on-year between 2014 and 2015.
The dominance of portfolio players holding unprecedented volumes with no obvious home could see the development of market liquidity jump from its current snail’s pace. The destination flexibility of homeless LNG means optimization plays, which ratcheted up in 2015, should become the norm while the marginal gains being made from LNG now and the even lower returns expected over the coming years are already forcing LNG sellers to be far more efficient in their dealings.

Up until a year ago profits were being made in the dollars, now they’re being made in the cents, which will see further synergies and partnerships opening up between sellers and between sellers and buyers across the globe, deepening liquidity in a traditionally illiquid market.

One significant obstacle is the practice of many LNG carriers operating along rigid routes. To develop a liquid LNG market, the LNG industry will have to prevent ships passing in the night. But in anticipation of a significant increase in LNG as a traded commodity, January saw the inauguration of a new charter party agreement, LNG VOY, which takes specific account of the increase in traded activity, approved by both the Baltic and International Maritime Council and the International Group of Liquefied Natural Gas Importers. Commodity house Trafigura is leading the growing number of traders that are forcing the industry to adapt, seeing its traded volumes increase 147% between 2014 and 2015 from 1.7 MMt to 4.2 MMt.

Alongside the flexible nature of the homeless LNG, its evolving indexation strengthens Poten’s expectations of market liquidity growth. Of contracts that were wholly or partly indexed to one or more gas hub in 2015 almost two-thirds of the volumes were linked to European hubs NBP and TTF compared to around a third linked to the US HH marker. Of those, both NBP in particular has deep liquidity on the longer forward curve.

The push by buyers for better terms was seen when India’s Petronet, for example, reached an agreement in principle to change its long-term contract with Qatar’s Rasgas. Under the agreement, the state-owned operator of the Dahej and Kochi terminals would lift another 1 million tons per year (MMt/y), increasing contract volume to 8.5 MMt/y beginning in 2016. Under the revised contract, Rasgas would effectively remove the price caps and floors, and the new pricing formula would include a constant of less than $1/MMBtu. Petronet’s earlier contract had no constant and set the price at a 12.67% slope to JCC. The pricing slope remains unchanged under the new terms.

Petronet’s exposure to higher crude prices was mainly due to a price floor that uses a 60-month rolling average of the JCC price. As a result, the state-owned operator had to pay spot prices of $12/MM Btu, compared with spot prices around $7/MMBtu. Petronet’s $1.5-billion penalty for not lifting enough cargoes will be waived under the new contract terms.

In addition to contract changes, the quality of buyers is also undergoing a shift, as new players emerge that have lower credit ratings, or in some cases are not rated by international agencies. So liquefaction project sponsors will need to sell cargoes or tolling capacity to companies with lower credit ratings, as players from new countries look to import gas.
They could be rated at the lower end of investment grade category – the last rung is triple B, which is Baa3 for Moody’s and BBB- for Standard & Poor’s and Fitch. But could also be sub-investment grade – Ba1 and lower for Moody’s or BB+ and lower for S&P and Fitch, or even unrated by international credit ratings agencies. Anything below B3 for Moody’s, and B- for S&P and Fitch is deemed high speculative and involves substantial risk. Figure 5, Credit Ratings of US liquefaction customers, shows that the later deals, such as Corpus Christi trains 1 and 2 have accepted a wider range of smaller offtakers with lower credit ratings.

Figure 4. Credit Ratings of Liquefaction Customers

The changes in the wider market are expected to play out – to some extent – in project financings. Project sponsors are competing to sign up customers to their schemes and those that are able to offer more flexibility are more likely to attract buyers or tolling counterparties. But what changes banks will allow to the tried and tested method of using long term offtake contracts to underpin project financings remains to be seen.

Banks and ECAs provide the loans because they are confident that the customer will continue to pay for the product and thus allow the project company to bring in revenue needed to service its debt. The bankability of LNG project financings, which are limited recourse to sponsors, is therefore driven by the creditworthiness of the offtaker, especially once any sponsor protections fall away, such as completion guarantees during construction.

These are widespread in LNG financings, but have only been used thus far in the US by Cameron LNG, which boasts premium grade sponsors Engie, Mitsui and Mitsubishi in addition to Sempra, and was able to supply a completion guarantee.

Signing up highly rated offtakers can allow smaller companies and those that are new to the sector to sponsor LNG projects, as has been the case in the US, with Cheniere, Freeport and the other entrepreneurs looking to construct liquefaction projects.
Banks will understandably be very reluctant to supply funding if they think the customer will default on payments for either LNG cargoes or the reservation of tolling capacity over the payback period of the loan. If an offtaker is not investment grade banks will look at whether they have options in the event of an offtaker default. If the contracts are not long term banks will also look at what options they have when contracts are up for renewal. If the liquefaction plant is in the lowest cost quartile, globally, banks will be more confident the production will find a buyer to replace the defaulter, and they are more likely to accept a higher mix of lower grade offtakers or tolling counterparties. Likewise, with projects that sit in the lower cost range, having customers signing up to shorter-term deals would become more feasible.

However, under the currently weaker market conditions and lower price environment, finding replacement customers would be more difficult. As a result the creditworthiness of buyers will come under more scrutiny. Banks are also likely to push for the security of longer term contracts. Their significance is illustrated by the recent developments at Cheniere’s Corpus Christi project. Banks had agreed to provide $3.1 billion in financing to train 3 of the project, in addition to supplying $8.4 billion to trains 1 and 2. The financing for trains 1 and 2 reached financial close last year, but the train 3 financing expired on December 31, 2015, because the company was unable to sign up a sufficient number of offtakers to allow it proceed.

But as the LNG market continues to evolve, financing models are expected to reflect some of the shifts in the wider market place, and rather than one type of financing, bespoke structures are likely to result. LNG project financing has already evolved to allow implementation of deals in new frontiers, be they geographic, or geological. Australia Pacific LNG, for example, which is based on coal bed methane (CBM) feedstock, secured contractual protection from the upstream for lenders to the liquefaction project. Exploiting coal beds for methane entails drilling thousands of wells for production and dewatering. Upstream drilling cost is lower than for a traditional reservoir, but so is productivity. Wells decline rapidly and if they are drilled and unused they fill with water.

There is greater uncertainty on CBM reserves at the start of the project and lenders have to assess a project’s viability based on 2P reserves or a 50% chance of reaching this reserves level, as compared with 1P or a 90% chance in LNG projects based on conventional gas reserves. The need to continuously drill wells spreads the upstream investment and thus upstream capital expenditure exposure over the whole of the project’s life. Some banks simply do not want to shoulder this risk. This issue of upstream risk came up again when BG sold the pipeline infrastructure for its Queensland Curtis CLNG project to Australia’s APA Group late in 2014. Lenders supporting the sale needed upstream protection.

So if protections are in place deals with unusual characteristics can get done. But it is telling that only one out of the three Queensland LNG projects based on CBM reserves used project finance.

Project finance structures and lender appetite for new types of risk will be tested again soon when the first floating liquefaction scheme seeks funding. Italian major ENI is examining project financing its Mozambique Coral floater and is planning to seek funds from banks this year for the $7 billion project.
Project financing deals had rarely been identical to one another, but future financings are likely to see greater variation and will probably mix some offtake or tolling of a shorter duration with long-term deals. This could even be priced at different levels, with the shorter duration offtake attracting higher pricing, although this adds complications to the structuring of deals.

Thus, banks will only lend—despite their need to grow their loan books—if they are comfortable with the commercial arrangements in place. The sponsors that attract bank funding will still be those that sign up a higher portion of long-term offtakers or tolling counterparties. But where the sweet spot for this mix will lie is hard to predict and finding it will require some experimentation.

Projects in other sectors—merchant power plants, toll roads, etc—do attract funds without long-term contracts in place. But the high implementation cost of liquefaction projects versus many of these types of deals will mean that lenders will remain attracted to the security of long-term contracts. Moving away from this, at least for the foreseeable future, will probably require measures to reduce lender risk through support such as sponsor guarantees. But bespoke financing that pushes the envelope is easier to implement for bigger companies that have higher credit ratings and a proven track record. Any liquefaction project that is considering going for full merchant risk would have to be sponsored by very large companies that can manage to balance sheet finance the deal. And this type of risk is unlikely to be embraced by even the largest companies if they can avoid it. The giant Gorgon project is being balance sheet-financed by its sponsors, but it still relies on long term offtake contracts.

Banks will exact a price for accepting project financings featuring shorter term offtake or sub-investment grade buyers. The amount of money that can be raised would fall because as risk increases, the achievable gearing level—debt to equity ratio—falls. The loan payback period, or tenor, could also be shortened, in order to assuage risk, but this would have implications for profit margins and dividend payments. And if the percent of lower-rated customers is too high for their palates, banks may reject the deal completely. Projects that are shunned by banks as too risky may attract funding from alternative sources, such as private equity, but this will command a significantly higher price. It remains to be seen how much exposure to the LNG sector alternative capital providers would seek and therefore, ultimately, how much money could be raised.

We conclude that long-term offtake will continue to drive funding provided via project finance structures, but that “long-term” may be shorter than it once was, and that long-term offtake/tolling will be mixed with contracts of shorter-term duration. Working out the best mix will be done on a case-by-case basis.