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Flexibility keys financing of Pacific Basin projects

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Current Pacific Basin market conditions appear to favor new liquefaction capacity. Considerable uncertainty exists, however, over the market's future. Financing decisions must be considered in light of a sponsor group's desire for flexibility, resources, and appetite for risk.

Access to US West Coast markets could alleviate some degree of market uncertainty, but committing to a regasification terminal that has yet to be constructed brings risks of its own.

A financing strategy that integrates terminal development into the LNG supply and marketing plan may be a viable option for tapping deeper liquidity within the Pacific Basin market.

Pacific Basin priorities

Despite the current global rise in LNG demand, the Pacific Basin will continue to be the largest market for the foreseeable future. Demand growth there is driven by economic recovery in Japan and Korea, concerns over global warming, and the growing need for new electricity-generating capacity in China and India.

LNG demand in this market is expected to grow at an estimated rate of 5-6%/year, to over 160 million tpy in 2014 from roughly 110 million tpy in 2007.

In response to this demand, a large number of Pacific Basin liquefaction projects are currently being developed. In fact, given the number of announced projects, the potential exists for the supply-demand balance to "flip"; that is, the current supply shortage could shift to a surplus by the middle of the next decade. Therefore, swift project execution has become a priority for many sponsors as they seek to lock in offtake contracts reflecting the current tight market.

The US West Coast market plays a prominent role in the plans of many sponsors as well. Access to it would provide additional depth to Pacific Basin demand and provide greater opportunities for arbitrage trade. The growing list of canceled projects, however, demonstrates that realizing a West Coast terminal is a difficult and uncertain task. Project sponsors must choose the financing that best equips them to meet the challenges of an uncertain market.

Market conditions

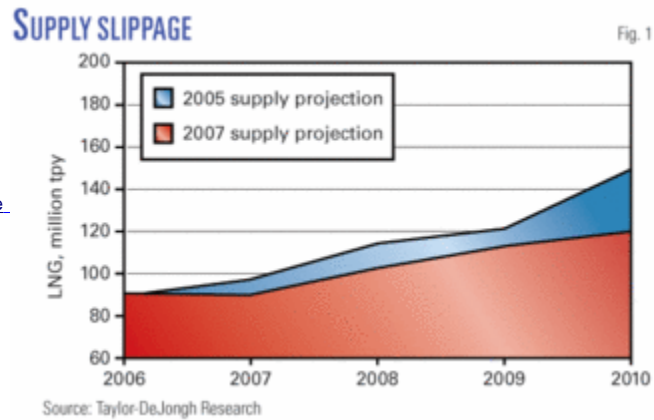
Although Pacific Basin LNG demand is on the rise, supply is struggling to keep up. Companies have seized upon this opportunity to gain market share and are committing to invest tens of billions of dollars into building new capacity. There remain, however, considerable uncertainties about the future state of the market.

The current LNG supply crunch and resulting high natural gas prices have created the potential for some demand destruction. Traditional LNG importers (Japan, Korea, and Taiwan) may diversify their energy portfolios to emphasize other sources as a result of rising gas prices.

Demand destruction is an even bigger threat in China and India. Even though these countries have the potential to become significant importers of LNG in the future, neither is fully committed to pursuing this energy source at current market prices.

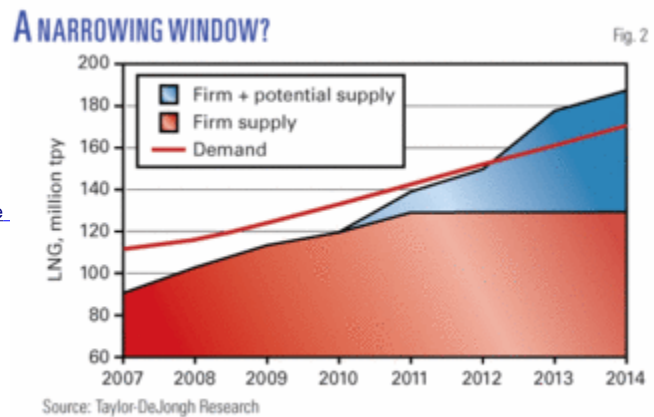
Finally, gaining access to the West Coast of North America has continued to prove difficult. Currently only one project on the West Coast, Sempra's terminal in Baja California, Mexico, is under construction. In comparison, on the other side of North America and along the Gulf Coast, six terminals are already in existence and five more are under construction.

Uncertain market conditions have been exacerbated by endemic project delays that are pushing back start-up dates for liquefaction projects worldwide. Fig. 1 illustrates how current estimates regarding upcoming Pacific Basin liquefaction capacity have slipped since 2005.



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Although delays have placed current LNG supplies in high demand, the near simultaneous entry of several new liquefaction projects in the 2013-14 timeframe could result in region-wide overcapacity and downward pressure on long-term contract prices (currently averaging \$8-10/MMbtu). The potential for lower prices as a result of overcapacity concerns many LNG project sponsors. Fig. 2 illustrates the prospects for a shift to a buyer's market as early as 2012.



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It should be noted that in 2005, many experts predicted the shift to a buyer's market would occur by 2010-11, a prediction that now seems unlikely. The same schedule delays that have led to the current tightness in the market could continue, pushing the seller's window back further.

Corporate vs. project financing

Uncertainty regarding the future of the Pacific Basin market has already affected the financing strategy of some projects in the region. One example is Woodside's Pluto LNG project.



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The single-train project will produce 4.3 million tpy of LNG and cost around \$9 billion. Woodside has signed 15-year offtake agreements with Japanese utilities for 3.75 million tpy. The company announced that it will fund the project through corporate debt and the company's free cash flow.

In the current market, this decision appears to offer several advantages. First, "all-equity" financing avoids the longer schedule often associated with project financing. LNG project finance deals are extremely complex, often involving multilateral and export credit agency (ECA) lenders that can take a relatively long time to complete their extensive due-diligence process. Given the potential for future surplus capacity, speed to market can be a significant competitive advantage for a project.

Corporate financing can also provide greater flexibility in marketing strategy. In project financing, lenders will examine downside scenarios in which the value assigned to production volumes that are not under long-term offtake contracts is heavily discounted.

As a result, a sponsor that seeks to reserve a "merchant" tranche of supply, in hopes of increasing upside through more opportunistic sales, may find the project subject to reduced leverage and more stringent debt covenants. In corporate financing, a sponsor can take its own view on the risks associated with more flexible marketing arrangements and act accordingly.

Corporate financings are more widely considered in today's market than they were several years ago. One reason is that the huge surplus cash flows brought by high energy prices have made the option more widely available. If oil prices were at \$35/bbl, Woodside and other companies like it might not have the resources even to consider balance-sheet financing for a \$9-billion project. Sustained oil prices at \$65/bbl and higher, however, have provided producing energy companies with a lot of choices.

All-equity financings have also become more attractive because sponsors have been assuming a greater share of project completion risk. A tight engineering-procurement-construction market has placed EPC contractors in high demand. Their ability to pick and choose the projects they undertake has made it less necessary for them to take on construction and completion price risk. These risks, therefore, have been pushed back on sponsors. As the exposure to overall completion risk increases, the construction-period risk profile of a project-financed project begins to look very similar to that of a corporate financing.

Even with the today's high energy prices, deciding to pursue balance-sheet financing is not without constraints and bears its own considerable risk. It is well understood that sponsors today are confronted by historically high capital costs. Global engineering services company Bechtel reports the cost of constructing a liquefaction facility has risen to as much as \$600/tonne/year of production capacity. This figure is three times greater than it was just 6 years ago.¹

When current capital costs are combined with the growing scale of today's projects-generally a single train is designed to be at least 4-5 million tpy-the result is a capital outlay of \$5 billion or more. Notwithstanding the huge profits that high energy prices have generated with the industry over the past couple of years, capital expenditures of this magnitude will be beyond the balance sheet for all but few corporations.

Pacific Basin liquefaction projects, as with most LNG projects, are also exposed to significant political and regulatory risks. Many of the countries in the Pacific Basin that have the potential to play host to an LNG project come with relatively high levels of country risk.

Host governments' actions can materially reduce a project's commercial viability, or at least add greater complication and uncertainty to a project's commercial structure. A project that is financed on the corporate balance sheet is fully exposed to this risk. Project-finance transactions, on the other hand, can be structured to mitigate country risk more effectively than a corporate financing.

ECA and multilateral lenders can be tapped to provide political risk instruments for both equity and debt. The involvement of these institutions in a project can also bring advantages through additional political leverage with the host government.

One overriding and obvious advantage of project financing is the boost to returns provided by the high level of leverage that can be attained, even in what are sometimes risky environments. The flexibility and speed of execution that can be achieved through corporate financing must be weighed against increased exposure to and reduced returns on the equity invested.

A refinancing strategy that uses the corporate balance sheet to underwrite construction and then replaces equity with project debt at the beginning of operations can be a practical approach to combining the benefits of both options. The need for sponsor completion guarantees makes the construction-period risk profile of the two strategies appear very similar.

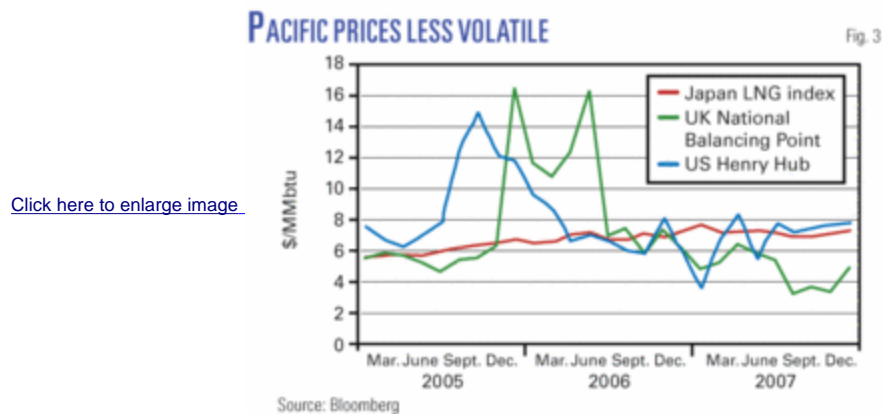
Once operations have begun, a non-recourse refinancing can reduce equity exposure and boost returns. If this approach is chosen, care must still be taken during project development to create a commercial structure that will protect the option for project financing, even though one may not be immediately at hand.

Cracking the West Coast code

Sponsors not only want to be first to market, they want to be first to the US West Coast market. The LNG market in the Pacific Basin is not as liquid as that of the Atlantic Basin. A higher degree of vertical integration within the natural gas industry and a relatively smaller number of industry participants make the Pacific Basin market less fluid.

Arbitrage opportunities also appear to be different than in the Atlantic Basin. Indexation to a 3-5 month rolling average of the regional oil price index-the Japanese Crude Cocktail-smoothes the Pacific Basin price curve somewhat, which in turn

dampens volatility (Fig. 3). Unlike in the Atlantic Basin where price swings between North American and European markets open arbitrage opportunities throughout the year, price swings in the Pacific Basin tend to be much more seasonal and are met through shorter term contracts and spot sales of LNG cargoes. When spot sales arise, they generally are from supplies intended for the Atlantic Basin, with Japanese and Korean utilities seeking volumes from, for example, West Africa and the Middle East.



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It is appealing to consider the impact of West Coast access. LNG terminal access to markets in California and the rest of the US West Coast would add significant depth and liquidity to the Pacific Basin market as a whole and provide new opportunities for arbitrage across the Pacific Ocean.

Nevertheless, financing regasification terminals on the West Coast poses problems of its own. First, these projects must clear domestic political and regulatory hurdles. In California, this has proven especially difficult, as evinced by the local government's rejection of a terminal proposed for the Port of Long Beach just south of Los Angeles and the state governor's veto of the Cabrillo Port, planned for off Malibu.

Woodside, however, appears to be making some progress with its terminal off Malibu. Good progress has also been made on permitting projects further north in Oregon that would serve Washington, Oregon, and Northern California markets.

Projects that are well-positioned from a regulatory standpoint face a second obstacle, a lack of readily available LNG supply. Current tightness in Pacific Basin LNG supply has left few creditable parties available to take firm capacity at any proposed West Coast terminal. For a terminal structured as a tolling facility, as are most of the proposed terminals, a long-term terminal-use agreement (TUA) for a majority of terminal capacity on a firm basis is essential. Without such an agreement a terminal will be unable to obtain debt financing.

From a lender's point of view, the largest risk in a tolling structure is the counterparty credit risk. An analysis of this risk should take into account not only the capacity holder's credit rating, but also the strength of its LNG procurement arrangements and its ability to market gas to the end customer.

One recent event that highlights the importance of a credit analysis of the full value chain concerns the Energía Costa Azul terminal in Baja California, Mexico. Sempra Energy, sponsor of the Costa Azul plant, has a 3.7-million-tpy offtake agreement with the BP-operated Tangguh LNG project in Indonesia. In June 2007, the Indonesian press reported that a significant portion of that volume would be diverted to other customers, including Indonesian state utility PLN. When the agreement was originally signed in 2004, BP characterized it as "highly flexible."² Therefore, the provision appears to have been part of the offtake agreement between the parties.

The situation, however, illustrates the importance of fully evaluating the risks up and downstream of a TUA, even when the counterparty brings an investment-grade credit rating. Issues such as the construction, operating, and country risks related to the source of the LNG supply, shipping arrangements, and natural gas marketing strategy all need to be carefully reviewed to assess the overall sustainability of the TUA.

Although a strong TUA with a creditworthy capacity holder may be sufficient to support the financing of a regas terminal, it may not be enough for the liquefaction plant. Take, for example, the situation in which the marketing plan for a given plant's LNG involves regasification at a terminal that has yet to begin construction.

Lenders to the supply plant will be reluctant to provide financing if offtake arrangements involve a regas facility that is still under development. Lenders will not want to assume the permitting, financing, and construction risks for the terminal and will pass them through to the sponsor's completion guarantee. If the sponsor is not the offtaker, the sponsor will probably pass the terminal completion risk to the offtaker through the LNG sales and purchase agreement.

In the end, whichever party is planning to offtake LNG and regasify it through its capacity at the terminal in question will be forced to bear completion risk for that terminal.

Under these circumstances it may make sense for the party bearing the terminal-completion risk to consider a significant equity investment, perhaps even a majority stake, in the terminal. Downsides to this approach include added capital budgeting requirements and reduced return on equity expected from an investment in regasification relative to a liquefaction project.

But there is considerable upside in owning a stake in the regas terminal, especially in terms of risk management. The ability to influence-or in the case of a majority stake, control-decisions throughout development and construction increases the ability to manage terminal-completion risk well beyond what is afforded through simply signing a TUA.

The impact on returns from investing in a less profitable regas facility is also small when viewed in the context of an overall investment in the LNG value chain. A regas terminal with a capacity of 1 bcf/d can be expected to cost about \$600 million to build. Assuming creditworthy agreements cover a majority of terminal capacity, project financing can achieve 80% leverage, leaving \$120 million for sponsors to finance through equity. In this scenario, an investment of \$75 million may be enough to secure a majority shareholding (51% of construction equity plus a premium).

Given the utility-style risk profile of a typical regas facility, returns to equity can be expected to be around 10-12%. This can be compared to a liquefaction plant that costs \$5 billion, is 60% levered-thereby requiring \$2 billion in equity-and is expected to provide an equity internal rate of return of 18%. Adding the regas cash flows to those of the liquefaction plant lowers liquefaction returns by less than 30 basis points. This relatively small reduction in expected returns is compensated by the ability to optimize risk management throughout the LNG supply chain.

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