

Achieving true market value

Sellers in long-term contracts increasingly are using netback pricing to capture maximum profits. By Jacob Dweck, Thomas Warren and Chad Mills, partners, global LNG group, Sutherland Asbill & Brennan

UNTIL the 1990s, LNG was typically sold to utilities in highly regulated markets, such as Japan, South Korea and continental Europe, with prices fixed or linked to the utility's cost of alternative fuel, such as fuel oil. However, with gas markets deregulating around the world, buyers and sellers are now more concerned with ensuring the price paid for LNG reflects its true market value in an importing country.

Theoretically, parties to an LNG sale into a deregulated market could base the price on the buyer's resale proceeds and, at the advent of the LNG boom earlier this decade, some parties spent months attempting to negotiate such provisions. When, predictably, this approach proved impractical, netback-price clauses pegged to a transparent gas index emerged as a logical and readily enforceable mechanism.

Negotiating and contracting considerations

Understanding netback pricing and gas indexation terms is critical for stakeholders – from the liquefaction supplier to consumer – which want to allocate transaction risks and benefits effectively. As in the case of Olokola LNG (OK LNG) – where NNPC's solicitation for 20-year purchase agreements required bids to be based on a netback price pegged to Henry Hub or NBP prices, regardless of the delivery destinations – there are significant negotiating and contracting considerations when using netback pricing for LNG based on gas indexation. These weigh most heavily in long-term contracts used to launch new liquefaction projects.

At its core, a netback price paid to the seller responsible for shipping is a function of: the agreed gas-index price at a specified gas delivery point; minus a negotiated percentage of the index price reflecting the buyer's margin; minus regasification, pipeline system entry and transportation costs. Most long-term transactions call for delivery by the seller. If the buyer is responsible for shipping (free-on-board), netback pricing must also reflect a deduction for the shipping costs.

Typically, the buyer's margin is captured by stating the contract price as a percentage of the selected index price (such as 90% of the US' Henry Hub). This percentage reflects the reality that, in netback pricing, the seller assumes nearly all price risk.

Ideally, the gas-index price should be based on published reported prices or exchange-traded futures prices for liquid trading points, such as Henry Hub or the UK's NBP. As LNG receiving terminals rarely de-

liver directly to these liquid trading points, it is necessary to include a basis component – the predicted difference between the index price used and the physical cash price at the tailgate of the receiving terminal.

At a minimum, basis (which can be positive or negative) will include theoretical transportation costs between the terminal and the liquid trading point (to the extent transportation costs are not directly deducted), but may also reflect supply/demand imbalances, pipeline constraints and other factors. Because, by its very nature, basis in this context is not based on transparent pricing, this can be one of the most difficult areas of price negotiation. Often, parties will directly or indirectly agree on a fixed basis to use for the life of the contract, shifting the entire basis risk, and benefit, to the buyer.

A timing risk also exists in the difference between the period over which the index price is measured and when the LNG is sold. For example, an LNG cargo delivered late in February might be priced based on the first-of-the-month price for February, but LNG from that cargo might not be sold until March. Given volatility in the deregulated US and UK markets, the index-cash differential could be significant, particularly in periods and at locations of peak demand. Because the buyer most commonly assumes this risk, it has the incentive to negotiate an index-based timing formula that affords it the greatest risk-management flexibility, including: employing inventory storage options; forward trades at a parallel pricing structure; or various futures and other hedging mechanisms.

Buyer assumes the costs

Deduction of the buyer's costs is inherent in the concept of netback pricing, although there are several ways to incorporate it into the parties' agreement. One way, more common in short-term and spot deals, is to have the buyer assume these costs as part of its negotiated margin percentage (for example, the seller's price is set at 85% instead of 90% of Henry Hub), or as a fixed deduction. In this situation, the seller receives a lower netback in exchange for price stability. The buyer assumes the risk of higher costs, but bets it can manage them effectively within the negotiated margin.

In most long-term contracts, however, netback pricing provisions include detailed enumeration of what costs can be deducted, when and how much. The buyer will want to pass on all costs to the seller, as the seller retains most of the profit in the chain. Conversely, the seller will want a fixed deduction from the contract price.

If the buyer has already contractually established the major components of its costs, the parties will typically compromise by having an initial fixed deduction (perhaps with an escalating portion), but allowing



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the buyer to pass on increased costs resulting from changes in taxes, laws or regulations in the delivery market. For cost increases, the greatest tension occurs where the buyer is in control of a substantial portion of these costs, for example where the buyer or its affiliate owns and operates the receiving terminal and the increased costs are passed through the buyer's terminal-use agreement with its affiliate. Here, the seller may press for protective provisions such as cost ceilings, prior notice and consultations, prudent operator requirements and seller audit rights.

At times, the parties may need to establish a price before large components of the buyer's costs are fully known – for example, if the buyer has not yet finalised its costs under its terminal-use agreement for regasification capacity. In this case, the buyer will want to pass on its costs once they are known, and the seller may ask for a cap and ask for extensive protective provisions. If the buyer is obtaining capacity from a terminal with regulated rates, a seller may be willing to rely on the regulatory process for its protection against regasification costs.

Each party to a long-term sale and purchase agreement (SPA) enters the negotiations with its best judgment of the forward gas price curve in the delivery location. In liquid markets such as the US, experience, futures markets and hedging opportunities may allow a measure of predictability in the near to medium term. But for most of the period covered in a 20-year contract, only clairvoyance can remove the significant risks that market prices could vary significantly from each party's expectations.

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The seller's primary worry is a netback price that makes it uneconomic to produce and deliver the contracted LNG. Project lenders may insist the seller include a floor price, or provisions allowing the seller to suspend deliveries, or terminate the agreement altogether at a certain price threshold. Conversely, having assumed most of the price risk, the seller also may press for a greater share of the profits by reducing the buyer's margin percentage if prices persist at high levels. Where the buyer agrees, the contract will specify varying netback percentages for different index-based price levels, calculated monthly or as an average over an agreed period. In some cases, the buyer has been able to cap margin reductions in exchange for a hardship floor price, or termination right that protects the seller.

For a buyer receiving LNG in a liquid market, there is little intrinsic need for price protection. While a precipitous price drop would affect the buyer's margin, the pricing formula will almost always allow for full-cost deductions. If the price skyrockets, the buyer's margin produces greater revenues. Even if the

buyer is an end-user and the high price renders consuming gas uneconomic (for example, a power producer), given the liquidity of the market the buyer should be able to resell the gas at the market price. However, if the price includes any type of floor for the seller, the buyer may attempt to negotiate a compensating ceiling price.

Price reopeners offer another means of addressing a future mismatch between economic expectations and market realities. For many years, periodic price renegotiations have been commonplace in long-term gas contracts in continental Europe, where there has not been a meaningful gas-based index. In the US, however, robust gas-market indexation began in the 1980s and even long-term domestic sales contracts typically use an index price.

The drivers for a price reopener in a gas-index contract are quite narrow, however. Generally, an index-based price formula would allow only for new negotiations when the selected index price is unavailable or, in extreme cases, where the method used to account for basis was known by both parties to be based on limited information and this method no longer reflects market conditions. Any rights to reopen price negotiations should be explicitly stated, or foreclosed, in the contract.

Destination flexibility

Negotiating for destination flexibility, also referred to as cargo diversion, has been in vogue recently as LNG sellers and buyers seek to maximise profits through the option to deliver to a higher-price market and not the originally agreed destination. A concern is the effect of diversion on the netback, index-based price calculation. Destination flexibility raises many other issues that must be addressed in the SPA, including interaction with applicable competition laws, shipping and logistical constraints, gas-composition concerns and risk-allocation issues.

In most cases, contract-based diversion rights (as opposed to changed destinations implemented by players within their own systems) are held by the party that controls shipping – the seller in most long-term contracts. The buyer's incentive is to ensure, primarily, that it is reimbursed for its costs and expected margin in the transaction, including any cover costs at the original destination that may exceed the cost allowance in the netback formula.

The parties must also negotiate whether, and how, the higher profits from the diverted cargo will be shared (consistently with competition laws). In determining the level of these profits, the contract must incorporate provisions to calculate accurately and deduct the diverting party's costs and savings, including shipping, regasification, processing and any market-access charges.

However a diversion clause manifests itself, it is reasonable to assume this type of provision will become an integral part of netback pricing, as parties attempt to share in the true market value of LNG regardless of its destination. ■