Features

Caribbean Basin LNG supply after Hormuz

The region's LNG supply architecture is under stress. Will contract structures prove resilient? **BY JOSE VALERA**, partner, **NATHAN GALER**, partner, and **CHRISTIAN SANCHEZ**, associate, **MAYER BROWN**.

A view past a liquified natural gas shipping vessel moored in Baughers Bay, Road Town, Tortola on a bright morning © Nicola Pulham | Dreamstime.com

The Caribbean, Colombian and Central American LNG markets do not typically buy gas directly from the Middle East – but the closure of the Strait of Hormuz is testing their supply architecture.

Even markets that source exclusively from the US Gulf Coast face real supply and pricing risk when global dislocations redirect American molecules towards higher-paying buyers in Asia and Europe. The region's increasing reliance on LNG creates an exposure that the Hormuz crisis has made evident. For key players in the region, the crisis poses a direct question: how should supply risk be managed when even geographically insulated markets face supply and global price pressures?

On February 28 2026, hostilities erupted in Iran. Within days, the Strait of Hormuz was closed, and roughly 20% of global LNG supply, most of it from Qatar's Ras Laffan export facility, was curtailed. Force majeure claims from LNG suppliers followed shortly thereafter, seeking to be excused from contractual delivery obligations to customers in Asia and Europe. By late April, the supply shock had repriced global gas markets unevenly: European TTF prices climbed more than 35%, Asian LNG benchmark JKM surged past 50%, and Henry Hub, buoyed by ample US domestic supply, fell 9%.[1] The result has been an arbitrage opportunity that could create strong incentives for US suppliers to redirect cargoes toward higher-paying markets.

For Caribbean basin buyers, the second-order effects are immediate. Asian buyers, who by some estimates receive over 80% of Qatari LNG,[2] are now competing for available cargoes on global markets, including US cargoes and volumes that might otherwise flow to the Caribbean region. Caribbean offtakers face both heightened direct competition for available supply and indirect pressure as US exporters weigh existing contractual commitments against significantly higher returns available in Asia and Europe. For key players in the region, the issue is no longer whether supply disruption is possible, but whether and how contracting strategy can withstand it.

Caribbean basin markets face a unique structural dependence on US Gulf Coast LNG and, to some extent, on Trinidad. They generally lack domestic natural gas production and viable pipeline alternatives.[3] Even before the Hormuz crisis, US-origin cargoes supplied an estimated 85% of imports to the Dominican Republic, Jamaica and Panama, the highest share on record.[4] And unlike utilities and industrial buyers in Europe and Asia, that may have greater capacity to absorb higher energy costs, Caribbean basin importers typically serve smaller, often consumer-based clients with more limited flexibility. In the Dominican Republic, for example, end-user electricity tariffs cover only about 60% of the cost of service, with the government bridging the gap through direct transfers to distribution companies.[5] When international spreads widen, regional buyers are price-takers with limited ability to compete.

Long-term contracts vs spot

Contract structure matters. The 2022 European gas crisis, stemming from the Russia-Ukraine conflict, made that clear: offtakers with long-term Henry Hub-indexed purchase agreements maintained relatively stable supply at predictable prices, while spot buyers faced significant price volatility. Caribbean basin importers responded by securing or extending long-term arrangements. The Hormuz crisis is now testing those decisions under conditions more extreme than most had planned for.

Long-term contracts lock in a margin, typically US dollar-denominated, above an agreed index, such as Henry Hub, Brent or TTF, for the life of the contract that covers liquefaction costs and returns, plus an opportunity cost that reflects market conditions at the time of pricing.

Shipping costs for DES deliveries may or may not be disaggregated. While buyers remain subject to commodity price volatility, the Henry Hub Index has historically been among the most stable relative to TTF and Asian benchmarks, and project finance

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lenders in the region are generally comfortable underwriting Henry Hub price risk given the passthrough structure and a fixed margin that covers liquefaction costs and returns. The trade-off is real: in periods of excess supply, buyers may pay above prevailing market rates under the locked-in formula. But over a full commodity cycle, the stability and predictability have supported longer-term credit analyses. The question going forward is not whether long-term contracts matter, but whether legacy terms are robust enough if disruption caused by the Hormuz crisis persists or worsens.

The trend across the region is toward long-term, Henry Hub-indexed arrangements. Recent transactions, including a 15-year sales and purchase agreement between TotalEnergies and Enadom in the Dominican Republic[6] and a 20-year Venture Global offtake agreement which is expected to supply Excelerate Energy's Jamaica position[7], illustrate the model that sponsors and lenders have come to expect: fixed pricing formulas and substantial tenors that support project finance. Puerto Rico has extended its long-term supply position[8] and Honduras has secured its first long-term SPA[9]. Markets that have secured such arrangements have greater price certainty in the current environment. Markets with greater spot or short-term exposure, such as Colombia's SPEC LNG terminal at Cartagena, face different risk dynamics.

Henry Hub indexation

The price stability that long-term Henry Hub-indexed contracts provide is also what draws offtakers' attention to those contracts. As of late April, the spread between Henry Hub at US$2.50/MMBtu, and Asian JKM at US$15/MMBtu, exceeds US$12/MMBtu. On the other hand, depending on the additional margin agreed in a particular transaction and transportation costs, for suppliers locked into Henry Hub-indexed SPAs, that gap represents forgone revenue on every cargo delivered to the Caribbean basin rather than redirected to higher-paying markets.

Portfolio sellers with flexible sourcing or short-term commitments can redirect available volumes to Asia or Europe and capture the arbitrage more quickly. Single-source arrangements and contracted volumes are less flexible. Deliberate failures to deliver are rare because of the reputational consequences that may affect future offtake negotiations. Redirecting committed cargoes may also trigger non-delivery remedies. SPAs now commonly include significantly higher liability caps, or no cap at all, for wilful failure to deliver for commercial reasons. The calculation for any seller considering such an option is whether current spreads are wide enough – and expected to persist long enough – to justify those costs.

More flexible price structures are typically disfavoured by sellers, project finance lenders, and buyers alike because they complicate hedging and introduce price uncertainty. Despite this, buyers are likely to face increasing informal pressure: sellers may condition consent requests or amendment negotiations on pricing discussions, or signal that future cooperation depends on revisiting commercial terms.

This dynamic is not new. Following the 2022 European gas crisis, some US FOB project sellers sought to renegotiate margins, even where they lacked formal contractual mechanisms to reopen pricing. Regional buyers should anticipate similar pressure if the current environment persists.

Key negotiation issues

In the current environment, two contractual issues are likely to feature even more prominently in purchase and sale agreement negotiations: non-delivery remedies and pricing. Both pit contract protections against the commercial pressure of current spreads.

Under a typical LNG supply arrangement, when a seller fails to deliver, the consequences depend on the cause. Force majeure may excuse performance, but agreements typically exclude market price movements and loss of profitability from force majeure definitions, making it almost impossible for sellers to convert a price spike into excused non-performance.

It is a different matter where a seller wilfully fails to deliver – for example, as part of a conscious redirection of volumes to higher-priced markets rather than fulfil contractual commitments. In this instance, cover damages would be owed to the buyer, although the scope of damages that are covered and any associated caps on the same are topics for negotiation in a particular transaction.

As the Hormuz crisis continues, these force majeure and cover damage provisions are increasingly likely to take centre stage during negotiations. This is particularly true for many Caribbean basin buyers, for example, where cover in the form of replacement deliveries in the traditional sense may be impractical. Many lack alternative fuel sources and access to other LNG terminals, so replacement procurement within required timeframes may not be feasible or may only come at great commercial cost. As a result, damages for non-delivery may need to expressly capture downstream consequences such as offtake penalties, compensatory payments under local electric market regulations, financing costs, and the cost of buying replacement power in the wholesale market, with the liability cap sized appropriately.

Pricing is a second key issue. From the seller's perspective, the pressure to capture international price upside is real and understandable given current spreads. Formal price reopener provisions are uncommon in US Gulf Coast FOB contracts because they represent an unacceptable risk for project finance lenders. Sellers may push for hybrid pricing mechanisms that blend Henry Hub indexation with international benchmarks, or for periodic price review clauses. One approach may be to transition from one index, eg, TTF-linked pricing in early years, to another, eg, Henry Hub-linked pricing for the balance of the term.

This structure may smooth revenue volatility while maintaining the regionally preferred Henry Hub indexation over the long term when it matters most. Caps, floors, and/or averaging mechanisms can also provide some limited market responsiveness while preserving buyer cost predictability. Tiered pricing structures, where the seller receives a modest premium above a threshold spread, are another option.

Any such modifications could, depending on implementation, also stand to benefit buyers during low-price cycles. The 2020 demand collapse, when Asian spot prices briefly fell below US Gulf Coast prices, is not distant history. For any given project, the task will be to find the right mix of market exposure and long-term stability that works for sellers, buyers, and lenders. The question is which provisions can absorb adjustment, and which are requirements that lenders will not waive.

Bankability implications

The threshold question is whether the contractual architecture across a project's key agreements – the SPA, power purchase agreement, offtake agreements, and credit documents – can withstand prolonged supply disruption and price volatility.

In most Caribbean basin markets, LNG buyers are typically electric generation companies or utilities that sell electricity to end consumers, and their ability to absorb fuel cost increases depends on whether PPA pricing formulas or electric market regulations allow pass-through of LNG costs. Where PPAs lock in energy prices with limited adjustment mechanisms, a mismatch can arise: the buyer may be contractually obligated to purchase LNG at a price it cannot fully recover from power sales. This makes the alignment between SPA and PPA pricing formulas a threshold structuring issue, one that the current crisis has made evident.

If a seller does not deliver, whether due to force majeure, operational constraints, or a decision to redirect volumes to higher-priced markets, the buyer's downstream obligations do not pause. The buyer may not be able to procure alternative fuel, may not generate power, may not meet its PPA obligations, and may trip financing covenants. Even where PPA pricing formulas allow some pass-through of increased costs, there are limits to what end consumers and governments can absorb.

Key diligence points include tenor, non-delivery remedy mechanics, seller creditworthiness, and whether the seller has portfolio-wide sourcing flexibility. The latter can help to mitigate force majeure exposure to single-source supplies. Lender reserve requirements may need to account for the possibility that spot procurement during a crisis could cost multiples of long-term contract prices. Backup fuel capability (the ability to switch to diesel or fuel oil if LNG supply is interrupted) may carry additional weight in credit analysis, as may the scope of business interruption coverage.

The bottom line for lenders to buyside sponsors: projects with long-term Henry Hub-indexed supply from portfolio players and robust non-delivery remedies are well positioned to sustain debt capacity in this environment. For the narrower group of projects relying on short-term supply arrangements, the current environment may prompt more intensive diligence and tighter financing terms.

Conclusion

The Strait of Hormuz crisis has not created new risks for the Caribbean, Colombian and Central American LNG markets. It has revealed risks that were always present in the region's supply architecture. The value of long-term Henry Hub-indexed contracts has become evident, as has the role that non-delivery remedies play in allocating supply risk. However, certain contractual structures are being stress-tested against scenarios that, until February, seemed more remote.

If current conditions persist, the convergence of prolonged Hormuz disruption, sought-after US export capacity, and widening international price spreads may reshape more broadly how regional LNG projects are structured, priced, and financed. Expanding infrastructure investment (such as new import terminals in Colombia, Dominican Republic, Honduras, the Bahamas, and the eastern Caribbean) will diversify regional supply architecture and further reduce overall spot market exposure over the next several years. ■

Footnotes

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