Addressing the Constraints on LNG Investment in Vietnam

Summary of World Bank Group Technical Assistance

Background

This report summarizes the results of technical assistance and policy dialog delivered by the World Bank Group (WBG) between March 2018 and March 2019. The technical assistance was aimed at facilitating Vietnam's strategy of importing LNG to address rapidly growing energy demand. The Ministry of Industry and Trade (MOIT) requested the technical assistance and served as the primary counterpart for the WBG. However, EVN, PVN, PV Gas and other public and private stakeholders were also involved.

Vietnam has a long-standing policy orientation that emphasizes the crucial role of natural gas in supplying reliable, competitive electricity while meeting national carbon emissions targets. Based on the current outlook for domestic production, Vietnam will need to import significant volumes of LNG beginning within the next 5-10 years, necessitating at least US$7-9 billion of investment in LNG import infrastructure. The recently completed WBG report on Maximizing Finance for Development (MFD) identified the key constraints on mobilizing investment in LNG-to-power, namely: a) lack of a modern regulatory and planning approach; b) lack of a bankable integrated commercial framework for LNG-to-power; and c) limited government experience with managing LNG pricing and volume risks. The WBG technical assistance provided detailed analysis addressing the constraints on LNG investment identified in the MFD report.

The analytical work generated by the WBG is contained in three reports: a) Legal and Regulatory Framework for LNG-to-Power; b) LNG Demand Projection, Procurement Strategy, and Risk Management; and c) FSRU Siting and Configuration Options.[1] The results of the studies have been presented and discussed in a series of stakeholder workshops and private executive briefings held in Hanoi and Ho Chi Minh City from November 2018 through March 2019.

Principal Findings

The key findings and recommendations emerging from the technical assistance and policy dialog are the following:

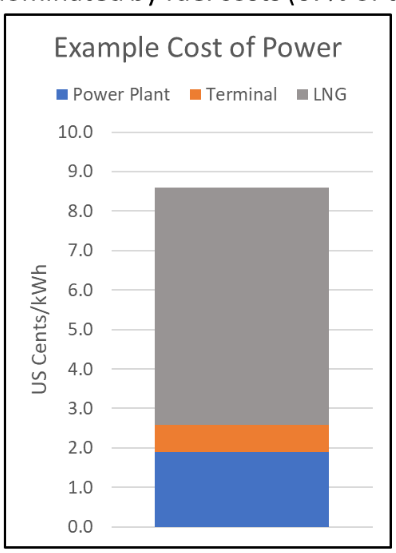
1. The two most important variables that ultimately determine the unit cost of electricity in an LNG-to-power project are the delivered cost of the LNG itself and the import terminal utilization factor (Figure 1);

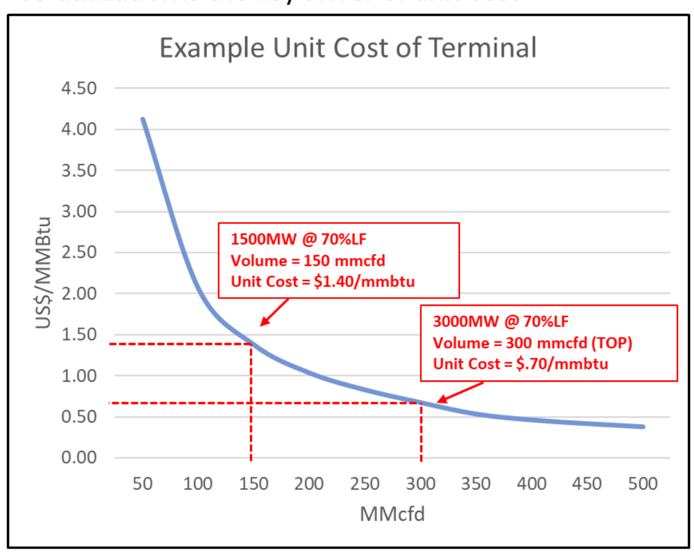
[1] *Studies a) and b) were prepared by The Lantau Group, supervised by the World Bank, and funded by a grant from ESMAP. Study c) was prepared by COWI, supervised by the IFC, and funded by a grant from The Japan Quality Infrastructure Trust Fund.*

2. The "PPP Tolling Model" (described below) is recommended as the most suitable commercial structure for Vietnam's initial LNG projects;
3. Vietnam should implement competitive processes wherever feasible, but particularly for LNG supply;
4. LNG terminals should be operated under an open access regime that provides for regulated tariffs and mandatory, non-discriminatory third-party access (TPA);
5. The potential to utilize FSRU's to accelerate LNG development and improve the bankability of infrastructure projects should be more fully explored.
6. Under current market conditions and by utilizing competitive and efficient procurement of LNG supply and infrastructure, gas can be delivered to power plants in Vietnam for around US$10/MMBtu, resulting in levelized electricity cost of approximately US$90 per MWh.
7. Vietnam's approach to LNG is already displaying good regulatory practice in several key areas, but the existing legal and regulatory framework for LNG-to-power needs further development and clarification.

These findings and recommendations are discussed briefly below. More detailed discussion is contained in the consultant reports that formed the analytical foundation for the technical assistance.

Figure 1: LNG-to-Power Economic Drivers





Assumptions: LNG price $9/mmbtu; CCGT efficiency 58%; CCGT capex $938/kW; terminal costs $80m/yr

Source: WBG Estimates

Policy Objectives and Regulatory Principles

Vietnam's paramount policy objective for LNG import projects should be to obtain fuel supply and infrastructure under terms that are compatible with the requirements of the electricity sector. In the first instance, this means delivering LNG-fired power that is cost-competitive with Vietnam's other energy supply options. It also means maximizing the flexibility of supply and infrastructure arrangements to create option value from long-term and short-term fuel switching, facilitate integration of renewable energy, and counteract the relatively inflexible, high take-or-pay characteristics of Ca Voi Xanh and other future domestic gas sources. Finally, LNG should address the security of supply concerns of the electricity sector, meaning that it should be reliable and should be developed in time to meet demand growth.

From discussions with MOIT and other stakeholders, the World Bank Group has concluded that Vietnam's other key public policy objectives for LNG import projects include:

1. Achieve competitive electricity and gas markets with full liberalization to be achieved in the 2020s. This would include a redefinition of the role of SOEs.
2. Attract private capital (domestic and foreign) into the gas and electricity sectors to fill the gap between total investment needs and the financing capacity of the public sector.
3. Minimize public sector risks coming from long-term commitments, government guarantees, SOE losses, subsidies, etc.;
4. Move quickly to capture the cost and flexibility benefits afforded by the current highly-competitive global LNG market.

The regulation supporting these policy objectives must be fair for customers, sustainable for investors, and efficient for the economy. Price regulation should be focused on segments of the LNG-to-power value chain that constitute natural monopolies such as LNG terminals, pipelines, and power transmission lines. International best regulatory practice in this arena is normally based on applying a weighted average cost of capital to a regulated asset base to arrive at capital recovery allowance, and then adding operating expenses, taxes and special charges to arrive at total revenue requirement.

On the other hand, in naturally competitive segments of the value chain such as bulk gas supply and generation, regulation should open the way for competitive forces to drive prices. Establishing competitive gas and electricity markets has reliably been shown to drive down energy costs in WBG client countries.

The full complement of regulations needed for the long-term development of LNG-to-power will take time to construct. At the outset, however, the initial regulatory principles that could be applied are:

1. Non-discriminatory TPA should be applied to LNG storage and regasification facilities;
2. Competitive processes for procurement of LNG supply should be employed;
3. Projects should be subject to price and access regulation if they seek to recover costs from the regulated electricity sector, utilize scarce or strategic national resources such as key sites and deep-water port capacity, or receive any form of government financial support or credit enhancement;
4. MOIT/ERAV should be assigned the mandate of assessing the reasonableness of proposed costs for activities where competition is not present or possible;
5. Reasonably incurred volume and price commitments from LNG supply arrangements should be passed through to electricity customers via tariffs.

Commercial Frameworks

The PPP Tolling Model is recommended as the commercial structure that is most compatible with the policy objectives and regulatory principles discussed above (Figure 2). The distinctive feature of the PPP Tolling Model is the separation or "unbundling" of a terminal company that provides LNG storage and regasification services under a terminal use agreement (TUA) with the LNG buyer. The terminal company is strictly a service and capacity provider and does not buy or sell LNG or gas. In the case where an FSRU is employed, the terminal company is the entity leasing the FSRU and contracting for construction of mooring and transfer facilities. In the case of a land-based terminal, the terminal company is the entity that enters into an EPC contract for construction of the terminal.

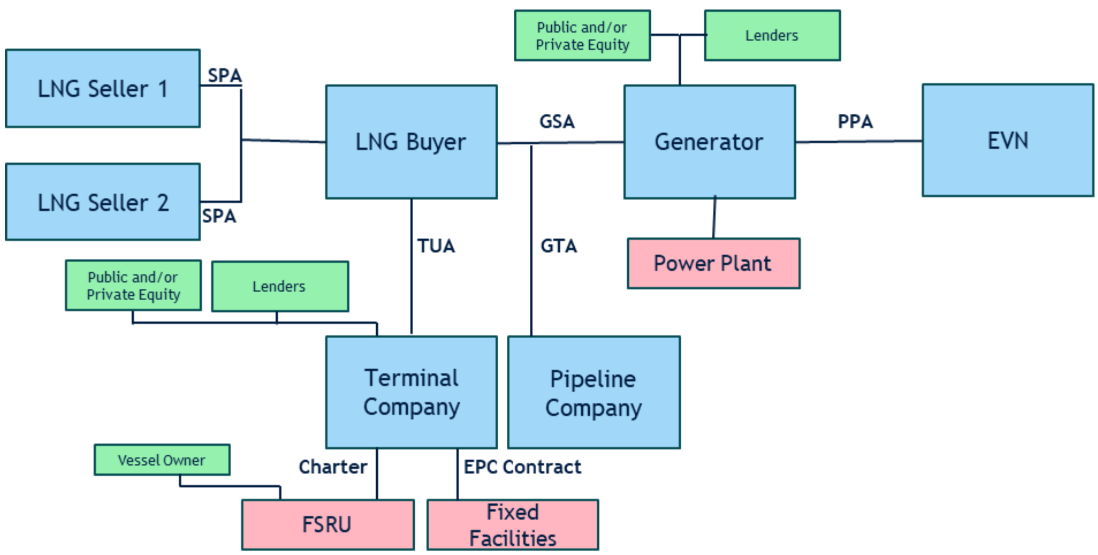
The advantages of the PPP Tolling Model include:

1. Creates a bankable terminal entity that can attract private capital and expertise;
2. Promotes competitive procurement of LNG supply and terminal infrastructure;
3. Creates a logical and transparent allocation of incentives and risks to the entity best able to manage them;
4. Can be structured under public, private or PPP ownership of each link in the value chain;
5. Can adapt as policy, regulation and market mechanisms evolve;
6. Facilitates more targeted application of government financing or guarantees;
7. Consistent with future gas sector liberalization, TPA, unbundling, and changing SOE roles;
8. Demonstrated success in other new Asian LNG importing countries (discussed below).

Designation of the entity that will act as LNG buyer is an important decision in implementing a tolling structure. Many countries have found it useful to designate the national oil company (NOC) as the LNG buyer in the first LNG import project, because the NOC serves as a credible commercial counterpart that international LNG sellers can rely on. Use of the NOC also signals an implicit guarantee of government's intention to make the project work. For this reason, designating PV Gas as the LNG buyer in Vietnam's first LNG import project could make sense.

However, there is no reason to create an enduring national LNG import monopoly. A wide range of possible commercial entities can serve as effective LNG buyers. Power generators, in particular, are usually extremely astute fuel buyers because of their direct understanding of generation requirements such as load factor, dispatch patterns, hydro availability, seasonality, etc. In the long term, Vietnam should allow EVN, IPP operators, distribution companies, traders and other entities to procure and market LNG utilizing the storage and regasification services of an LNG terminal company.

Figure 2: PPP Tolling Model for LNG-to-Power

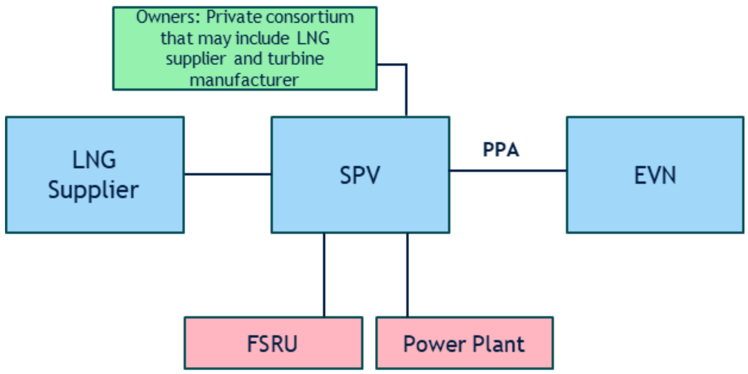


Key Agreements in Tolling Structure:

- SPA = LNG Sales and Purchase Agreement
- TUA = Terminal Use Agreement
- GSA = Gas Sales Agreement (not needed if Power Generator is LNG Buyer)
- GTA = Gas Transportation Agreement (not needed if power plant and terminal are co-located)
- PPA = Power purchase Agreement

An alternative to the Tolling Model is the Integrated Model ("one-stop shopping") wherein the power purchaser enters into a PPA with a special purpose entity that assumes responsibility for the entire value chain including LNG supply, LNG terminal and power plant (Figure 3). The major concerns associated with this structure are the reduction in competition for the LNG supply, the potential creation of an unwanted infrastructure monopoly, and the difficulties in implementing TPA (especially *ex post*) within the integrated structure. However, the Integrated Model has seen success in Latin American countries with fully-competitive electricity markets. In these cases, competition for the award of the PPA itself brings about the cost discipline and competitive tension in each element of the value chain. On the other hand, there are very few instances where direct negotiation of an integrated PPA have yielded a successful result. One-on-one negotiations usually bog down over highly-inflexible seller demands including high levels of government guarantee.

Figure 3: Example Integrated LNG-to-Power Model



LNG Procurement Strategy

Two decades ago, LNG was considered to be an expensive and highly-inflexible energy import alternative. Asian LNG trade was conducted mainly via integrated, back-to-back contractual chains linking upstream production, liquefaction, shipping, regasification, and marketing. The LNG market was concentrated in a small number of sellers—large resource holders such as Indonesia's Pertamina—and a handful of investment grade utility buyers in Japan, Korean and Taiwan. LNG contract prices were almost without exception oil indexed.

Today more than 40 countries are importing LNG and contracting practices have moved towards far more flexible and buyer-friendly arrangements including greater use of short-term contracts and spot sales, lower take-or-pay (TOP) volumes, shorter contract terms, and greater destination flexibility and cargo diversion rights. An increasing share of sales come from "portfolio players", large oil and gas companies such as Shell, ExxonMobil, and Total that control multiple LNG supply sources and have access to multiple markets. Although oil-indexed pricing still dominates, buyers also have new pricing options that include Henry Hub (US) indexation, fixed price, and hybrid terms (Figure 4).

Global LNG trade was approximately 320 million tons per annum (mtpa[2]) in 2018.[3] The current market is over-supplied by approximately 20 percent as a result of the wave of new production capacity that came on line over the last decade, mainly in the US and Australia. With a further

[2] 1 mtpa is approximately equal to 133 million cubic feet per day or 1.3 billion cubic meters per annum.
[3] WB estimate based on Shell, IGU, and IHS

170 mtpa of capacity having taken final investment decision (FID) in 2018 or poised to take FID in 2019-20, the industry is forecast to remain in a “buyers’ market” until at least the mid-2020s. The average oil indexation factor under newly-signed, long-term LNG SPA’s has decreased from 14 percent in2007-2013 to less than 12 percent in 2018.[4]

Figure 4: LNG Contracting Trends

Traditional LNG Contracting	Recent LNG Contracting
Long term (20+ years)	**Shorter contract length (≤10 years), more spot market transactions**
Large contract volumes (>1.5mtpa)	**Smaller contract volumes (<1.5mtpa)**
Contract between suppliers and credit-worthy utilities	**New classes of market participants: portfolio players, traders, over-supplied utility buyers**
Supply from a specified export facility	**Supply increasingly from a portfolio, no defined source**
Fixed destination clauses	**Greater destination flexibility, cargo diversion and cancellation rights**
High TOP requirements	**Lower TOP requirements**
Oil indexation (typically 14-15% of oil price)	**New options for pricing: HH-linked, fixed price; structural shift to lower slope (<12%)**

Source: The Lantau Group

The increased contracting flexibility, structural over-supply, more intense competition, and lower prices exhibited in the current LNG market create a highly favorable environment for Vietnam as a potential new LNG buyer. Addressing this market requires a very focused, competitive procurement strategy that should include the following elements:

1. Conduct a detailed definition of gas volume requirements to include minimum demand, average demand, maximum demand, seasonal and daily variations, etc.;
2. Design a supply portfolio comprising medium-to-long-term contracts covering minimum requirements and short-term “strips” of 1-3 cargoes covering seasonal variations in demand and hydro generation, supplementing with spot cargoes as demand requires.
3. Conduct competitive tender/bid procedures for all contracts;
4. Hire experienced commercial and legal advisers;
5. Purchase LNG on a Delivered-Ex-Ship (DES)[5] basis, rather than FOB;
6. Provide LNG sellers with a clear and credible plan for financing and construction of the LNG terminal, pipelines, and power plants needed to commercialize LNG.

[4] Sources: Company data, Citi Research, IHS Markit, and Wood Mackenzie.
[5] Sometimes also called Delivered-at-Place (DAP)

The choice of price indexation is a particularly important matter. For Asian LNG buyers, the widely available options are:

1. Oil indexation (usually to Brent): this is still the most common index
2. Henry Hub: growing in use as US LNG export capacity increases
3. LNG Spot: the JKM spot price marker is now liquid enough to act as a price index
4. Fixed price: mainly available for short- and medium-term purchases
5. Hybrid: combination of two or more of the above options

World Bank Group commodity price forecasts as of October 2018 suggest that Henry Hub indexation could produce marginally lower LNG prices than oil indexation over the long term. The World Bank's view on Henry Hub prices is influenced by published resource estimates and long-run marginal cost analysis showing that more than 1200 trillion cubic feet (34 trillion cubic meters) of North American gas resources could be produced at Henry Hub prices of US$4 or less. However, it is worth remembering that the World Bank, like many other institutions, has a generally poor track record of predicting oil and gas prices. Faced with this uncertainty, Vietnam's procurement strategy should include seeking price quotations from suppliers under a variety of price indexation regimes and diversifying price risk over time.

Portfolio players, by virtue of their access to diversified sources of supply, are well placed to supply LNG under the pricing terms and with the volume flexibility required by the Vietnamese market. Vietnamese buyers should avoid getting locked into long-term, inflexible supply arrangements such as FOB purchases, liquefaction capacity reservation, and upstream production interests. For example, Henry Hub price indexation, if desired, can be achieved via a contract with a portfolio seller without the need to reserve long-term capacity at a US liquefaction facility.

FSRU Utilization and Siting Options

A Floating Storage and Regasification Unit (FSRU) is a permanently-moored LNG tanker that has been modified to include onboard regasification equipment. The FSRU receives ship-to-ship transfers of LNG from arriving LNG tankers, stores the LNG, and delivers natural gas into a high-pressure gas pipeline connection to shore. FSRUs have proven to be a very flexible and cost competitive storage and regasification solution. An FSRU-based terminal can be operational within three years (post-FID) for a new-build vessel and two years for conversion of an existing tanker. FSRUs are typically leased which reduces the initial capital outlay. Also, the movable nature of the FSRU mitigates credit risk and allows relocation of the FSRU if import needs or demand conditions change. As a result, FSRU-based terminals have proven to be easier to finance than land-based terminal in smaller markets with non-investment grade off-takers.

The costs associated with an FSRU-based terminal are typically US$80,000 to 90,000 per day for lease of the FSRU itself plus US$130-200 million for mooring infrastructure and pipeline connection. By contrast, a land-based terminal typically involves an up-front outlay of at least US$500 million. In many cases, the total cost of service for an FSRU-based terminal is lower than for a land-based terminal, although this is highly site-dependent.

FSRUs are very sensitive to metocean conditions (wind speeds, wave heights, ocean currents and major storm occurrences). As such, FSRUs do not have universal application. FSRUs exposed to harsh metocean conditions may have unacceptably low availability, and extensive dredging or costly breakwaters can negate the cost and financing advantages of FSRUs. Vietnam's coastline presents challenges to the utilization of FSRUs because of the limited availability of deepwater locations near to shore with natural protection from wind and waves.

The IFC-led FSRU siting and configuration study performed a preliminary screening of twelve potential FSRU sites in south and southwest Vietnam, from which four locations were selected for further, more-detailed technical analysis. The short-list selection was based on input from stakeholders and agencies; proximity to existing power plants and/or natural gas transmission pipelines; metocean exposure and natural sheltering conditions; and navigation and mooring bathymetry (water depths). Each of the four short-listed sites were evaluated for: i) exposure to cyclones and monsoons (extreme conditions); exposure to long-period swells (operational conditions); proximity to populated areas or industrial facilities; bathymetry, dredging considerations, sedimentation, and infilling; geotechnical conditions; navigation and waterway suitability; and available shore space and access. Preferred mooring options were identified for each location along with capital cost estimates.

The study identified two potential FSRU sites worthy of additional investigation. A site close to Long Son Island in Vinh Ganh Rai and a site in the Ca Mau pipeline corridor were both determined to have the potential to accommodate a permanently-moored FSRU under operating conditions where ship-to-ship transfer could be performed reliably. The Long Vinh Ganh Rai option would utilize a clustered guide pile mooring system, and the Ca Mau location would use spread mooring or submerged soft yoke systems depending on final sight selection. Further engineering and design work is necessary to determine final feasibility of these locations.

FSRU implementations were deemed to be technically feasible at a near-shore site near Mui Ke Ga, and at Long Hai near the Nam Com Son (NCS1) pipeline. However, both of these locations commonly experience ocean and wind conditions that are too rough for ship-to-ship transfer at a commercially acceptable level of availability. In addition, FSRUs located at these exposed sites would need to unmoor and come off station when in the path of a typhoon.

Lessons from International Experience

To support the findings and recommendations under the technical assistance, the World Bank Group examined the experience of other recent Asian LNG importers (Figure 5). This analysis pointed out the following:

1. With the exception of Indonesia, all recent LNG entrants have employed some form of tolling model to structure the LNG import project;
2. With the exception of Singapore, all new importers have employed FSRU;
3. Some form of competitive procurement has been employed in most projects;
4. In most instances, both the LNG buyer in the SPA and the gas off-taker have been SOEs for the first projects. In subsequent projects, private entities have usually taken up these roles;
5. Some form of government guarantee was needed in most instances.

Figure 5: Recent Asian LNG Import Projects

Project, Country	COD	Business Model	Type	Government procurement method	LNG Buyer in SPA	Gas offtaker	Government guarantees
SLNG, Singapore	2013	Tolling model	Onshore	SLNG (EMA subsidiary) issued an EPC tender	Aggregator	Private sector	SOE investment
Moheshkhali, Bangladesh	2018	Tolling under a 15-yr BOOT	FSRU	Direct Appointment (by use of Speedy Support Act).	Public entity aggregator (Petrobangla)	Public entity (Petrobangla)	G-to-G, Government guarantees Petrobangla's obligations.
Engro Elengy, Pakistan	2015	Tolling under a 15-year agreement	FSRU	Competitive tender.	Public entity (Pakistan State Oil Company (and Sui Southern Gas Company)	Public entity (Pakistan State Oil Company (and Sui Southern Gas Company)	G-to-G, Government guarantees
Java 1, Indonesia	2021	Integrated under a 25-yr PPA with a BOOT arrangement	FSRU and 1,760 MW CCGT	Competitive tender	Public entity (PLN)	Power Co. of Consortium (Marubeni, Pertamina, Sojitz)	No, but NEXI is providing political risk and commercial risk insurance to commercial lenders
Colombo LNG Terminal, Sri Lanka	2021	Tolling model, 20 year BOT	FSRU	Swiss Challenge	Public entity	Public entity	G-to-G, Government guarantees
Jaigarh, India	2018	Tolling	FSRU	n.a. (private initiated project)	Not disclosed	Not disclosed	None

Source: The Lantau Group

The Moheshkhali LNG import project in Bangladesh is considered to be a useful case study for Vietnam to examine. Moheshkhali is an FSRU-based terminal based on the tolling approach. This project went from the concept stage in 2015 to first delivery in 2018. Project components were transparently and competitively bid (vs non-transparent, bilateral negotiation) to achieve faster results, lower costs, and accelerated project implementation. Moheshkhali is structured as a PPP with the assistance of the IFC which holds a 20% equity stake in the project. IFC's participation mobilized debt financing from five international lending institutions. Petrobangla was both the LNG buyer/aggregator and the gas off-taker for the Moheshkhali project, but subsequent LNG import projects planned in Bangladesh will involve private parties.

ACRONYMS AND CONVERSIONS

BCM	Billion cubic meters
EVN	Vietnam Electricity Company
FSRU	Floating Storage and Regasification Unit
GGU	Government Guarantee and Undertaking
IFC	International Finance Corporation
IGU	International Gas Union
LNG	Liquefied natural gas
MIGA	Multilateral Investment and Guarantee Agency
MOIT	Ministry of Industry and Technology (Republic of Vietnam)
MTPA	Million metric tonnes per annum
MWh	Megawatt hour
PPP	Public-private partnership
PVN	PetroVietnam
SOE	State-owned enterprise
TOP	Take-or-pay
TPA	Third-party access
WBG	World Bank Group

Natural Gas Conversions*

From: To:	BCM	TCF	T btu	MBOE	MTOE	M tonnes (LNG)
BCM	---	0.0353	35.7	6.60	0.90	0.74
TCF	28.30	---	15.11	190.0	25.50	20.7
T btu	0.028	0.0010	---	0.18	0.025	0.021
MBOE	0.15	0.0054	5.41	---	0.14	0.11
MTOE	1.11	0.0392	39.7	7.33	---	0.82
M tonnes (LNG)	1.37	0.048	49.6	8.97	1.22	---

* Based on indicative industry averages. Actual conversion is dependent on variations in gas and crude oil compositions.