Chapter 2

LNG Infrastructure Development and Financing in Select ASEAN Countries: The Philippines, Viet Nam, Indonesia, and Myanmar

November 2021

This chapter should be cited as

Study Team (2021), 'LNG Infrastructure Development and Financing in Select ASEAN countries: The Philippines, Viet Nam, Indonesia, and Myanmar', in Hashimoto, H. and F. Lee (eds.), *A Flexible LNG Market and Promotion of Investment.* ERIA Research Project Report FY2021 No. 15, Jakarta: ERIA, pp.11-42.

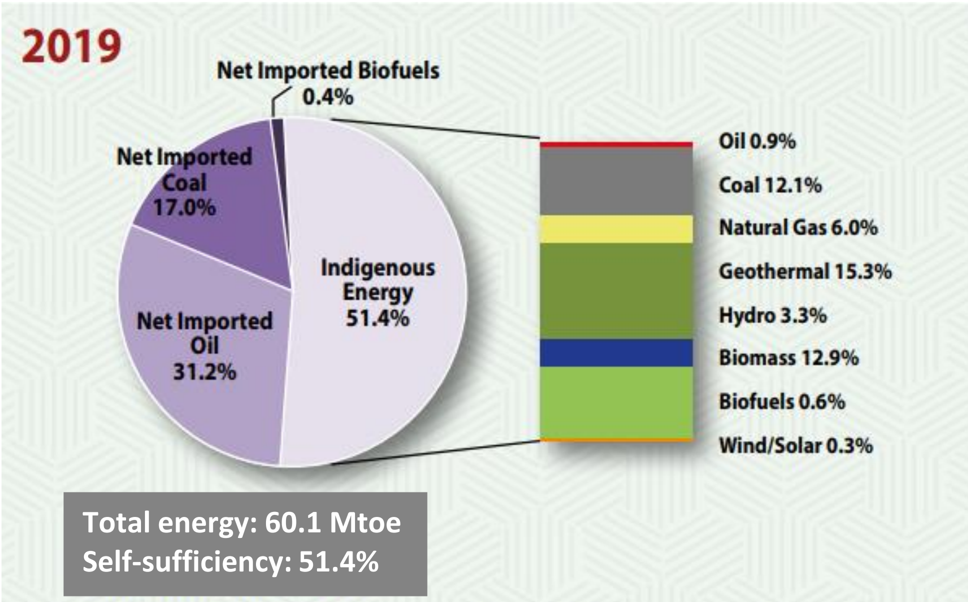
Chapter 2. LNG Infrastructure Development and Financing in Select ASEAN Countries: The Philippines, Viet Nam, Indonesia, and Myanmar

2.1. The Philippines

Background

The Philippines's TPES was 60.1 Mtoe in 2019 (DOE, 2019). Half of the supply is indigenous energy, of which geothermal (15.3%), biomass (12.9%), and natural gas (6.0%) accounted for the largest share of indigenous supply. Oil (31.2%), coal (17.0), and biofuels (0.4%) were the three imported energy, which made the country's self-sufficiency rate 51.4% in 2019.

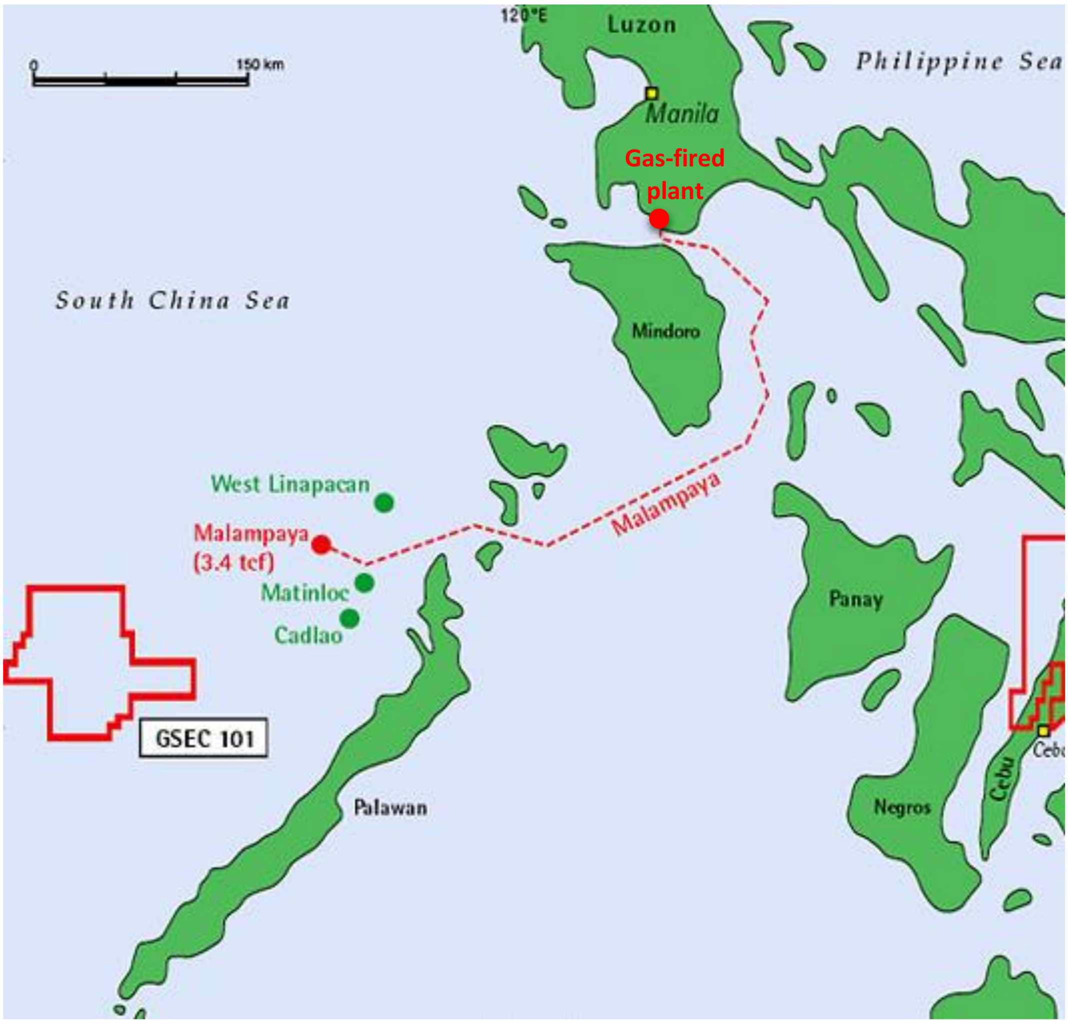
Figure 2.1. The Philippines's Primary Energy Supply Mix, 2019



Source: DOE (2019).

The Philippines has always been self-sufficient in natural gas since 1994. Its gas production increased significantly in 2001 when the offshore Malampaya gas field, the largest gas field in the country, started production. The field is located 80 km off the coast of Palawan Island, with proven reserves of about 2.7 trillion cubic feet (Tcf) of natural gas. The Malampaya gas field started commercial operation in June 2002 and began to supply gas to gas-fired power plants in Batangas. The field is scheduled to produce 146 billion cubic feet (Bcf) of gas per year (DOE, n.d.[a]). However, the DOE estimated that the known gas reserves would be depleted by 2024 (DOE, 2017a). The other two are San Antonio and Libertad gas fields. The San Antonio gas field was the first natural gas discovery in the country. It was located in Echague, Isabela, and was developed as a demonstration project of gas production with proven reserves of 2.7 Bcf. The field started commissioning in 1994 and ended in 2008 because of depletion (DOE, n.d.[b]). The Libertad gas field is southeast of Bogo town proper in northern Cebu, producing only less than 1% of the total gas supply in the country (DOE, n.d.[c]).

Figure 2.2. Malampaya Gas Pipeline Route to Gas-Fired Power Plant



Source: US Securities and Exchange Commission (2005).

The Philippines started producing natural gas in 1994. The production increased significantly in 2002 when the Malampaya gas field began commercial production. The power sector consumed 100% of the natural gas until 2004; the industry sector has consumed 0.5% to 2.4% of gas since 2005. The power sector is still the main consumer of natural gas in the country.

Table 2.1. The Philippines's Natural Gas Production and Consumption, by Sector, 1994–2020

Year	Production (Mmscf)	Consumption (Mmscf)			
		Power	Industrial	Transport	Total
1994	195	195	0	0	195
1995	188	188	0	0	188
1996	318	318	0	0	318
1997	193	193	0	0	193
1998	329	329	0	0	329
1999	253	253	0	0	253
2000	376	376	0	0	376
2001	4,951	4,951	0	0	4,951
2002	62,205	58,120	0	0	58,120
2003	94,807	87,423	0	0	87,423
2004	87,557	83,959	0	0	83,959
2005	115,966	110,217	525	0	110,742
2006	108,606	104,229	2,193	0	106,422
2007	130,211	124,103	3,316	0	127,419
2008	137,073	129,044	2,932	15	131,990
2009	138,030	131,433	3,019	18	134,470
2010	130,008	121,943	3,044	15	125,002
2011	140,368	133,732	3,288	47	137,066
2012	134,563	127,616	2,473	51	130,141
2013	123,944	116,549	2,665	35	119,250
2014	130,351	122,305	3,302	4	125,611
2015	122,541	115,788	2,138	0	117,926
2016	140,516	132,350	2,782	0	135,132
2017	139,209	132,256	2,255	0	134,511
2018	150,804	142,723	2,550	0	145,273
2019	155,495	146,365	2,642	0	149,007
2020	141,732	132,009	1,597	0	133,606

Source: DOE (2021a).

In terms of power generation, coal is the largest fuel source, accounting for more than half of total power generation in the country since 2017. Natural gas and geothermal are the second and third sources, with 21% and 10% shares in 2019. The gas share of total power generation peaked at 30% in 2011 and declined to 22% in 2016. It has remained stable ever since. The installed capacity of natural gas was 3,453 MW in 2019, accounting for 14% of the country's total installed capacity, of which 3,200 MW came from the Malampaya gas field.

Table 2.2. The Philippines's Power Generation, by Source, 2009–2019

Unit: GWh	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	16.476	23.301	25.342	28.265	32.081	33.054	36.686	43.303	46.847	51.932	57.890
Oil	5.381	7.101	3.398	4.254	4.491	5.708	5.886	5.661	3.787	3.173	3.752
Natural Gas	19.887	19.518	20.591	19.642	18.791	18.690	18.878	19.854	20.547	21.334	22.354
Renewable Energy	20.191	17.823	19.845	20.762	19.903	19.810	20.963	21.979	23.189	23.326	22.044
Geothermal	10.324	9.929	9.942	10.250	9.605	10.308	11.044	11.070	10.270	10.435	10.691
Hydro	9.788	7.803	9.698	10.252	10.019	9.137	8.665	8.111	9.611	9.384	8.025
Biomass	14	27	115	183	212	196	367	726	1.013	1.105	1.040
Solar	1	1	1	1	1	17	139	1.097	1.201	1.249	1.246
Wind	64	62	88	75	66	152	748	975	1.094	1.153	1.042
Total	61.934	67.743	69.176	72.922	75.266	77.261	82.413	90.798	94.370	99.765	106.041

Source: https://www.doe.gov.ph/sites/default/files/pdf/energy_statistics/2019-key-energy-statistics.pdf

Unit: GWh	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	27%	34%	37%	39%	43%	43%	45%	48%	50%	52%	55%
Oil	9%	10%	5%	6%	6%	7%	7%	6%	4%	3%	4%
Natural Gas	32%	29%	30%	27%	25%	24%	23%	22%	22%	21%	21%
Renewable Energy	33%	26%	29%	28%	26%	26%	25%	24%	25%	23%	21%
Geothermal	17%	15%	14%	14%	13%	13%	13%	12%	11%	10%	10%
Hydro	16%	12%	14%	14%	13%	12%	11%	9%	10%	9%	8%
Biomass	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%
Solar	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%
Wind	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: DOE (2019).

Table 2.3. The Philippines's Installed Capacity, by Source, 2009–2019

Unit: MW	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	4,277	4,867	4,917	5,568	5,568	5,708	5,963	7,419	8,049	8,844	10,417
Oil	3,193	3,193	2,994	3,074	3,353	3,476	3,610	3,616	4,153	4,292	4,262
Natural gas	2,831	2,861	2,861	2,862	2,862	2,862	2,862	3,431	3,447	3,453	3,453
Renewable energy	5,309	5,437	5,391	5,521	5,541	5,898	6,330	6,958	7,079	7,227	7,399
Geothermal	1,953	1,966	1,783	1,848	1,868	1,918	1,917	1,916	1,916	1,944	1,928
Hydro	3,291	3,400	3,491	3,521	3,521	3,543	3,600	3,618	3,627	3,701	3,760
Wind	33	33	33	33	33	283	427	427	427	427	427
Solar	1	1	1	1	1	23	165	765	885	896	921
Biomass	30	38	83	119	119	131	221	233	224	258	363
Total	15,610	16,358	16,162	17,025	17,325	17,944	18,765	21,423	22,728	23,815	25,531

Source: DOE (2019).

Drivers of LNG Imports

The Malampaya gas field currently supplies 3,200 MW gas-fired power plants. However, the gas supply is depleting and becoming less reliable. The industry has revealed that there is always insufficient gas supply to the existing power plants, which puts the 3,200 MW of installed capacity in the Luzon grid at risk.

While no other domestic natural gas resources are enough to replace Malampaya's gas supply, the government promotes natural gas as an environment-friendly, secure, stable, and economically efficient energy source. There is an urgent need to attract more investments in the downstream LNG industry and import LNG for the existing gas-fired power plants in the Luzon grid. The country cannot yet access the international LNG market as there are no existing or operational LNG import facilities.

Regulatory framework support for LNG infrastructure development and investment

The government has already prepared the necessary policies as indigenous gas supply from Malampaya approaches depletion by 2024. DOE has stated that it is a priority to ensure a secure and stable energy supply by diversifying the energy mix through LNG (DOE, 2017a). The regulatory framework for LNG investment and development is as follows:

Philippine National Standard, 2016

The Philippine National Standard was promulgated on 20 June 2016. It provides the quality specifications for natural gas. The standards specify the requirements for all the natural gas commercially sold in the country (DOE, 2016).

Downstream Natural Gas Regulation, 2017

DOE issued the Downstream Natural Gas Regulation in 2017 to provide a regulatory framework (DOE, 2017b) for the downstream natural gas industry and transparent guidelines for investors in the Philippines, including:

- industry compliance to policies, rules, standards, and best practices on siting, design, construction, expansion, modification, and operation and maintenance of any gas-related projects;
- industry compliance on importation of LNG, supply, and transport of natural gas;
- providing for the legal, technical, and financial documentary requirements, application procedure, evaluation process, criteria, and permits.

Executive Order No. 30 - Creating the Energy Investment Coordinating Council to Streamline the Regulatory Procedures Affecting Energy Projects, 2017

This executive order provides for energy projects amounting to at least US$70 million to be classified as Energy Projects of National Significance (EPNS). Also, it mandates the streamlining of the permitting process of all government agencies under the Energy Investment Coordinating Council to act on proposals within 30 days if the project is considered an EPNS; otherwise, the proposal is deemed approved (DOE, 2017c).

Republic Act 11032 - Ease of Doing Business and Efficient Service Delivery Act, 2018

To further facilitate the LNG investment, the Ease of Doing Business and Efficient Service Delivery Act set a standardised deadline for government transactions:[9]

- 3 days – simple transactions of business entities
- 7 days – more substantial transactions
- 20 days – highly technical transactions

Infrastructure development of LNG imports

The permitting process comprises three stages: (i) notice to proceed (NTP); (ii) permit to construct, expand, rehabilitate, and modify; and (iii) permit to operate and maintain. There are currently seven proposed LNG receiving terminal projects.

[9] IEEJ–ERIA Workshop, 'A Flexible LNG Market and Promotion of Investment in ASEAN – Under a New Era of Price Volatility and Energy Transition', Philippines' presentation material, 2021.

Table 2.4. Status of Proposed LNG Terminal Projects in the Philippines

Proponent	Partner Company	Project	Location	Capacity	Estimated COD[a]	Target Market	Application Status
FGEN LNG Corporation (80%)	Tokyo Gas (20%)	FSRU and LNG Terminal	Barangays Sta. Clara, Sta. Rita Aplaya, and Bolbokin Batangas City	5.26 mtpa	Q3 2022	1) Existing gas-fired power plants, namely, 1,000 MW Sta. Rita; 500 MW San Lorenzo; 414 MW San Gabriel; and 97 MW Avion. 2) Proposed 600 MW Sta. Maria and 600 MW St. Joseph power plants.	Permit to Construct on 23 September 2020
Excelerate Energy L.P.	Topline Energy & Power Dev Corporation (Filipino) (currently planned for 30%)	FSRU and LNG Terminal	About 9.5 km offshore in Bay of Batangas	4.4 mtpa	Q3 2022	EGCO Group (small-scale LNG break bulk capacity) and Third Party Access model (transparent and non-discriminatory open access model)	1) Notice to Proceed (NTP) issued on 20 September 2019 2) NTP extension letter (6 months) issued on 27 May 2020 3) NTP extension (3 months) due to force majeure

Batangas Clean Energy, Inc (51%)	LCT Energy and Resources Inc. (Filipino) (49%)	LNG Storage and Regasification Terminal	Barangay Pinamucan-Ibaba, Batangas City	3 mtpa	Q4 2025	Self-owned gas-fired power plant (1,100 MW) and anticipated gas demand from potential users located near the project site: 1) JG Summit Petrochemical Plant 2) Tanduay Distillers	1) NTP issued on 20 March 2020 2) NTP extension of 9 months (6 months plus 3 months due to force majeure or COVID-19 quarantine)
Energy World Gas Operations Philippines Inc. (100%)	None	LNG Storage and Regasification Terminal	Barangay Ibabang Polo, Pagbilao Grande Island, Quezon Province	3 mtpa	Q4 2022	Self-owned gas-fired power plant (650 MW) in Quezon province in 2021	Permit to Construct issued on 21 December 2018, valid for 2 years
Atlantic Gulf & Pacific Company of Manila, Inc. (AG&P)	Osaka Gas	FSU and Onshore Regasification	Barangay Ilijan and Dela Paz, Batangas City	3 mtpa	Q2 2022	1,200 MW Ilijan Power Plant in Barangay Ilijan, Batangas City	NTP issued on 24 February 2021

Shell Energy Philippines, Inc. (SEP) (100%)	None	FSRU	Tabangao, Batangas City	3 mtpa	Q3 2022	1) AC Energy proposed gas-fired power projects in Mariveles and Subic 2) JG Summit Petrochemical Corp for 81 MW existing power plant and 30–40 MW expansion	NTP issued on 16 Mar 2021
Vires Energy Corporation (VEC)	None	FSRU and LNG storage and regasification terminal	1.6 kilometres from the south-eastern coastline of Batangas Bay in Barangay Simlong, Batangas City	3 mtpa	Q1 2023	a 500 MW floating power plant	Notice to Proceed (NTP) issued on 22 April 2021

[a] Commercial operation date.

FSU = floating storage unit, FSRU = floating storage regasification unit.

Source: IEEJ–ERIA Workshop, 'A Flexible LNG Market and Promotion of Investment in ASEAN – Under a New Era of Price Volatility and Energy Transition', Philippines's DOE presentation material, 2021.

DOE has stated that the LNG infrastructure sector is a private sector–led and –driven initiative, and the government is dependent on the private sector (*Business World*, 2021). As of 13 May 2021, five LNG terminal projects targeted for operations from 2022 to 2025 received an NTP. Two projects proposed by FGEN LNG and Energy World Gas Operations Philippines Inc. received permits to construct, which is the second stage of the permitting process. DOE mentioned that financial viability is one of the main criteria used to evaluate the application, and the government supports the project to proceed if it is financially viable.

Also worth noting is that FGEN LNG's original plan was to construct an onshore LNG terminal featuring a 200,000–cubic metre (m^3) onshore storage tank. But after considering the costs and time frame, FGEN LNG decided to pivot towards an interim offshore LNG terminal, which could be ready to accept a floating storage regasification unit (FSRU) in 2022. FGEN LNG is only required to modify the existing jetty without demolishing it with the interim offshore terminal. Furthermore, in April 2021, First Gen Corporation announced that it had selected BW Paris of BW Group as its FSRU, which has an LNG storage capacity of 162,400 m^3. The lease is for 5 years, and it is expected to receive the first cargo in the fourth quarter of 2022.

LNG outlook for the country

The Philippines desires that the upcoming LNG imports will help the country attain gas supply security for power generation and other potential natural gas applications in the industry, commercial, residential, and transport sectors.

In March 2021, DOE announced to promote the Philippines as an LNG hub that will ultimately serve the energy needs of the country and the Southeast Asian region. The government also called LNG terminal investors to address a common goal – expanding the Philippines's LNG and clean energy industries (DOE, 2021b).

Lastly, if all seven proposed LNG projects were completed and fully utilised, the total LNG receiving capacity in the Philippines would reach 24.66 mtpa.

2.2. Viet Nam

Background

Viet Nam's TPES was 83.46 Mtoe in 2018. Coal accounts for the largest share of 44%, followed by oil (2%) and natural gas (10%).[10] The total installed capacity in 2020 was 69.2 GW; hydro (30%) and coal (29%) are the largest sources, followed by oil and renewables (26%) and oil and gas (13%). In the same year, coal contributed half of the country's power generation, followed by hydro (30%) and oil and gas (14%).[11]

Like the Philippines, Viet Nam is self-sufficient in natural gas supply and heavily relies on coal. Five operating natural gas pipeline systems are currently operating (Table 2.5): (i) Cuu Long

[10] IEA, 'Viet Nam', https://www.iea.org/countries/viet-nam#reports

[11] IEEJ–ERIA Workshop, 'A Flexible LNG Market and Promotion of Investment in ASEAN – Under a New Era of Price Volatility and Energy Transition', Viet Nam's presentation material, 2021.

Basin Pipeline System (2 billion cubic metres [Bcm]), (ii) Nam Con Son Gas Pipeline System (7 Bcm), (iii) Phu My–Nhon Trach Pipeline System (phase 1: 2 Bcm, phase 2: 3.8 Bcm), (iv) Phu My–My Xuan–Go Dau Low-Pressure Gas Pipeline System (1 Bcm); and (v) PM3 CAA–Ca Mau Gas Pipeline System (2 Bcm).[12]

Table 2.5. Viet Nam's Natural Gas Pipeline System

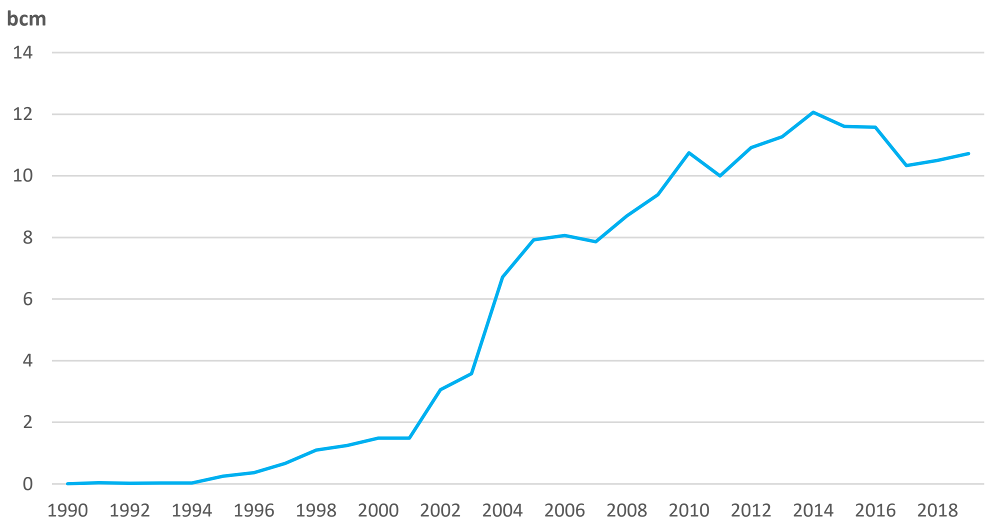
Gas Pipeline	Capacity	Transport Destination
Cuu Long Basin Pipeline System	2 Bcm	Ba Ria, Phu My power plants, Phu My Fertilizer Plant, and consumers
Nam Con Son Gas Pipeline System	7 Bcm	Nam Con Son Gas Processing Plant
Phu My–Nhon Trach Pipeline System	2 Bcm (phase 1) 3.8 Bcm (phase 2)	Power plants in Nhon Trach, Hiep Phuoc, and consumers along the pipeline
Phu My–My Xuan–Go Dau Low-Pressure Gas Pipeline System	1 Bcm	Consumers in Phu My–My Xuan–Go Dau Industrial Parks
PM3 CAA–Ca Mau Gas Pipeline System	2 Bcm	Power Plants of Ca Mau No. 1 and No. 2

Source: PVN, Major Projects, https://www.pvn.vn/sites/en/Pages/detailv4.aspx?NewsID=4c4ab3a0-8568-4a12-af85-6e1857a2111a (accessed 17 September 2021).

Viet Nam's natural gas production has increased significantly since 2001, growing from 1.48 Bcm to around 12 Bcm in 2014 and slightly declining to 11 Bcm in 2019 (see Figure 2.3.).[13] The majority of natural gas supply is consumed in the power sector. In 2018, 87% of the gas supply is consumed in power generation (APERC, 2021).

[12] PVN, Gas industry major projects, http://www.pvn.vn/sites/en/Pages/detailv4.aspx?NewsID=4c4ab3a0-8568-4a12-af85-6e1857a2111a?

Figure 2.3. Viet Nam's Natural Gas Production



Source: Compiled by IEEJ with IEA's data (IEA, Viet Nam, 2021, https://www.iea.org/countries/viet-nam#reports)

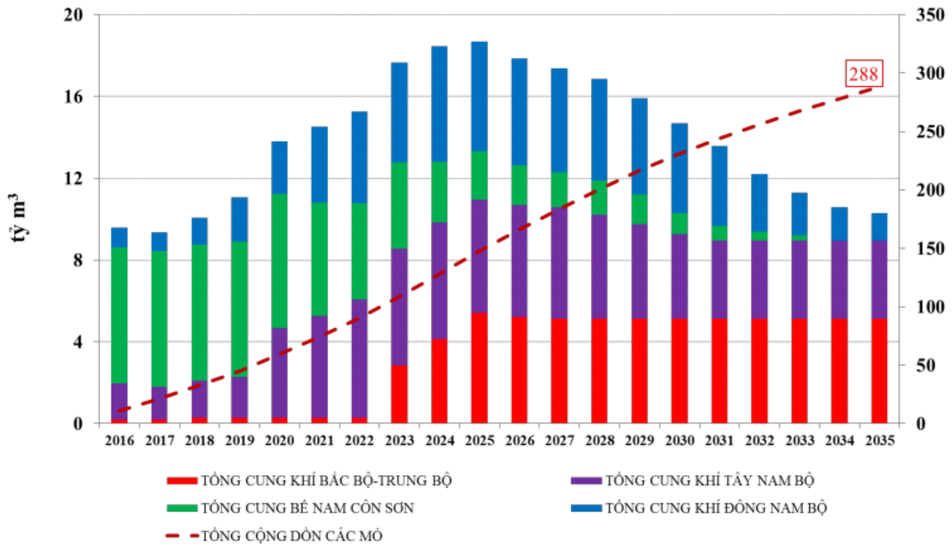
As a developing economy, the country's population and economy have been growing fast since 2000. Its population grew by 21%, from 80 million in 2000 to 96 million in 2019. Its GDP grew by more than seven times from US$31 billion in 2000 to US$262 billion in 2019.[14] Parallel with the fast economic growth, energy demand also grows significantly, especially in the power sector. Power generation grew almost ninefold from 23 TWh in 2000 to 227 TWh in 2018. The trend is forecasted to continue.[15]

Viet Nam's master plan for gas industry development and import target

Again, like the Philippines, the Viet Nam government has forecasted that the natural gas resource will be depleted in the next decade, dropping from a peak of about 19 Bcm to around 10 Bcm in 2030 (Figure 2.4).[16]

[14] World Bank, https://data.worldbank.org/indicator/NY.GDP.MKTP.CD?locations=VN.
[15] IEA, Viet Nam, https://www.iea.org/countries/viet-nam#reports.
[16] MOIT, 'Vietnam Gas Industry Master Plan', http://www.jccp.or.jp/country/docs/4_CPJ-5-18_MOIT.pdf (accessed 10 September 2021).

Figure 2.4. Viet Nam's Natural Gas Production Forecast, 2016–2035



Source: MOIT , 'Vietnam Gas Industry Master Plan, http://www.jccp.or.jp/country/docs/4_CPJ-5-18_MOIT.pdf (accessed 10 September 2021).

Recognising the important role of gas in the country, the government aims to develop other domestic gas resources and import LNG. For domestic development, under the government's direction, the Viet Nam Oil and Gas Group, Petro Vietnam (PVN), and PV Gas, a major subsidiary of the PVN, are developing two major gas projects to deliver 5–7 Bcm of additional gas supply per year from Block B, Ca Voi Xanh field to southern and central markets (APERC, 2021). These two projects are expected to produce gas in 2021 and 2023, respectively (Australian Government, 2019).

Besides, the government announced the master plan for gas industry development in 2016, planning to import LNG in 2021. The master plan set a target to import around 5 million tonnes of LNG by 2025, 10 million tonnes by 2030, and 15 million tonnes by 2035 (accounting for about 1.6% of total world LNG imports). The plan also forecasted that gas demand in Viet Nam would reach 11–15 Bcm per year in 2016–2020, 13–27 Bcm per year in 2021–2025, and 23–31 Bcm per year in 2026–2035 (MOIT, n.d.).

LNG terminal development

To achieve the LNG import target, the government encourages developing LNG terminal systems and related facilities. In 2021–2025, it plans to build three to four LNG terminals with an estimated capacity of 1–3 mtpa for each terminal mainly in southern Viet Nam. For 2026–2035, the government plans to build five to six LNG terminals with an estimated 3 mtpa for each terminal (MOIT, n.d.).

Two LNG terminals will be operating commercially soon: the Hai Linh LNG terminal and the Thi Vai LNG terminal.

The planned Hai Linh LNG terminal is owned by Vietnamese oil company Hai Linh Co. Ltd. and located onshore in the southern province of Ba Ria-Vung Tau. Construction is completed, and commercial operation is expected to start in 2021 with an initial capacity of 2–3 mtpa. It will have the potential to expand to 6 mtpa. After commercial operations in 2021, the Hai Linh LNG terminal, the first LNG terminal in Viet Nam, will supply natural gas to its Hiep Phuoc thermal power plant in Ho Chi Minh City. Hai Linh Co. Ltd. also talks about supplying gas to the state-owned power company Vietnam Electricity or EVN's power plants (S&P Global, 2020).

The state-owned PV Gas and its partners in the coastal area southeast of Ho Chi Minh City own the planned Thi Vai LNG terminal. Construction began in 2019 and is expected to be completed in October 2022. It will have a 1 mtpa capacity in the first phase in 2022, with the potential to rise to 3 mtpa in 2023 in the second phase (GIIGNL, 2021). The media reports that PV Gas signed master sales purchase agreements with Shell Singapore and Gazprom Marketing and Trading Singapore for LNG supply (Pham, 2020a).

The construction of the Son My terminal in Binh Thuan province is planned to start in 2021 (APERC, 2019a). The Bac Lieu project is also scheduled to start construction in 2021, and the completion is slated for 2024. It will be the first large-scale LNG project developed by a foreign investor, Delta Offshore Energy.

As domestic gas production declines, LNG demand is forecasted to surge in 2021–2022 when the power shortage is more severe in the south (i.e. Ho Chi Min City) and the domestic gas supply starts to be exhausted. In addition to new power plants intended to use LNG are those that previously planned to use coal but would like to switch to natural gas. Examples are the Long An (*Vietnam Investment Review*, 2020) and Vung Ang 3 power plants (Vietnam Energy Online, 2020).

Table 2.6. LNG Terminal in Viet Nam (including Planned Projects)

LNG Terminal		Capacity (mtpa)	COD[a]	Investor	LNG Import Source	Status
Hai Linh		2–3	2021	Hai Linh	N.A.	Completed construction, for operation soon
	(Phase 2)	6	N.A.		N.A.	Planning
Thi Vai		1	2022	PV Gas	N.A.	Under construction
	(Phase 2)	2	2023		N.A.	Planning
South West LNG (Ca Mau)		1	2022–2025	N.A.	N.A.	Planning
	(Phase 2)	2	After 2025	N.A.	N.A.	Planning
South East LNG (Tien Giang)		4–6	2022–2025	N.A.	N.A.	Planning
Thai Binh (FSRU)		0.2–0.5	2026–2030	N.A.	N.A.	Planning
North LNG (Hai Phong)		1–3	2030–2035	N.A.	N.A.	Planning
Khanh Hoa LNG		3	2030–2035	N.A.	N.A.	Planning
Son My, Binh Thuan		1–3	2023–2025	PV Gas, Shell, AES	N.A.	Planning
	(Phase 2)	3	2027–2030		N.A.	Planning

	(Phase 3)	3	2031–2035		N.A.	Planning
Ninh Thuan		6	N.A.	Gulf Energy	N.A.	Planning
Bac Lieu (FSRU)		3	2024	Delta Offshore Energy	United States	Planning
Thua Thien Chan May LNG		2.87	2024	Chan May LNG	United States	Planning
Cai Mep Ha			2023		N.A.	Planning
	(Phase 2)	9	2026	T&T Group, Gen X Energy	N.A.	Planning
	(Phase 3)		2030		N.A.	Planning

[a] Commercial operation date.

Source: IEEJ analysis.

Draft PDP 8 and LNG-to-Power project development

Since most natural gas is used to generate power, the power development plan is the anchor of LNG development as LNG-based power would determine investment direction. In March 2021, the Ministry of Industry and Trade of Vietnam released the draft national power development plan for 2021–2030, with a vision to 2045 (hereafter Draft PDP 8).

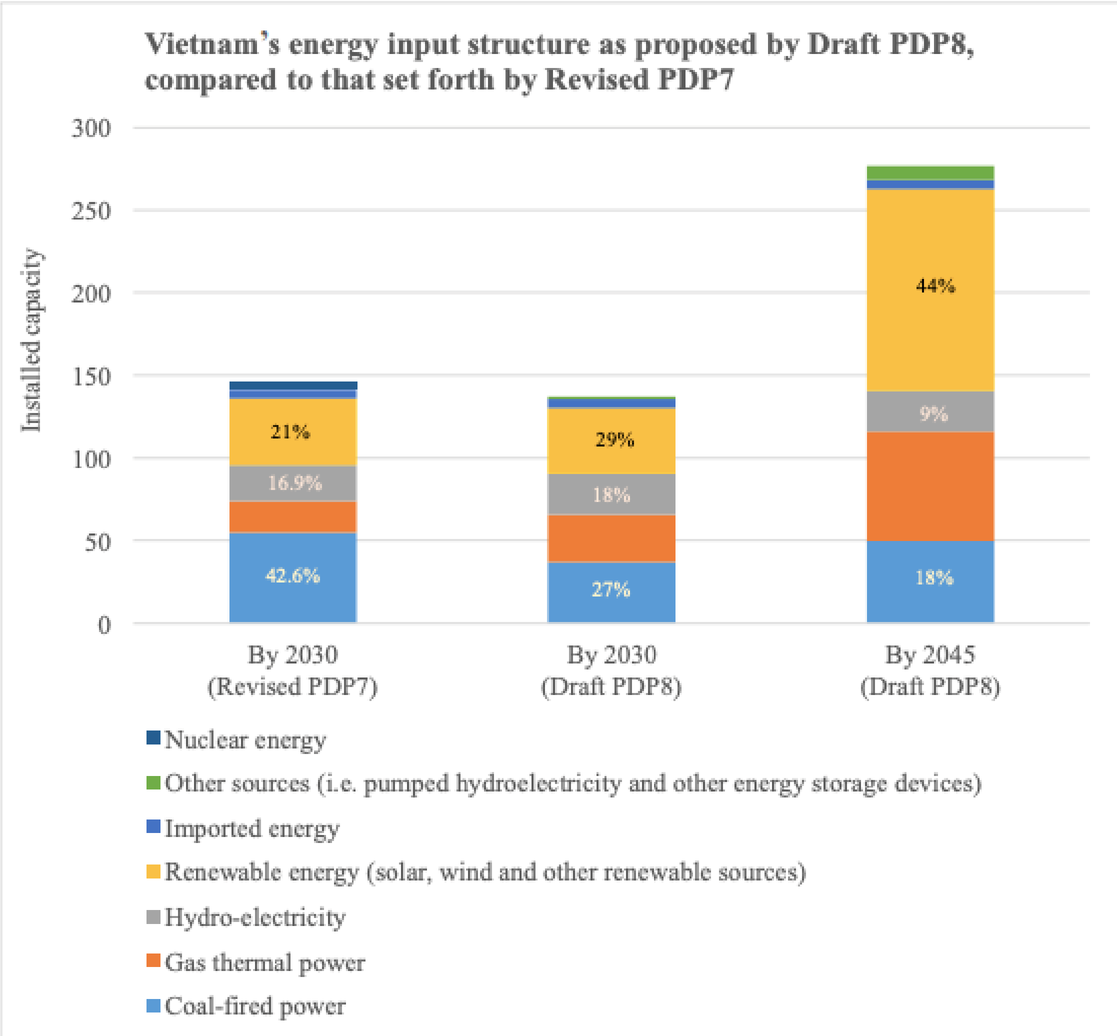
Draft PDP 8 shows a clear shift from a coal-focused capacity structure towards a renewable- and gas-focused capacity structure by 2045. The highlights of the Draft PDP 8 are as follows:

Coal-fired power: no new coal-fired power to be developed
Draft PDP 8 reduced the share of coal-fired power input from 43% in the Revised PDP 7 to 27%. No new coal-fired power plants will be developed except the ones already being constructed.

Gas-fired power: further increase after 2030
Draft PDP 8 increases the share of gas-fired power from 6% in the Revised PDP 7 to 21%. In addition, PDP 8 recommends a plan to construct an additional 5 GW gas-fired capacity in the north utilising LNG, 500–700 MW with flexible source (internal combustion engine, ICE) in the north, and 900 MW of ICE in the south.

Renewables: account for more than 40% of total capacity by 2045
The share of renewable energy, especially wind and solar, also increases from 21% in 2030 in the Revised PDP 7 to 29% in Draft PDP 8, and further increases to 44% in 2045. By 2030, onshore and offshore wind power is expected to reach 9 GW and 3 GW, and solar 7 GW.

Figure 2.5. Viet Nam's Installed Capacity Structure, Comparison of Revised PDP 7 and Draft PDP 8 (MW)



Source: Ohno and Tsunematsu (2021).

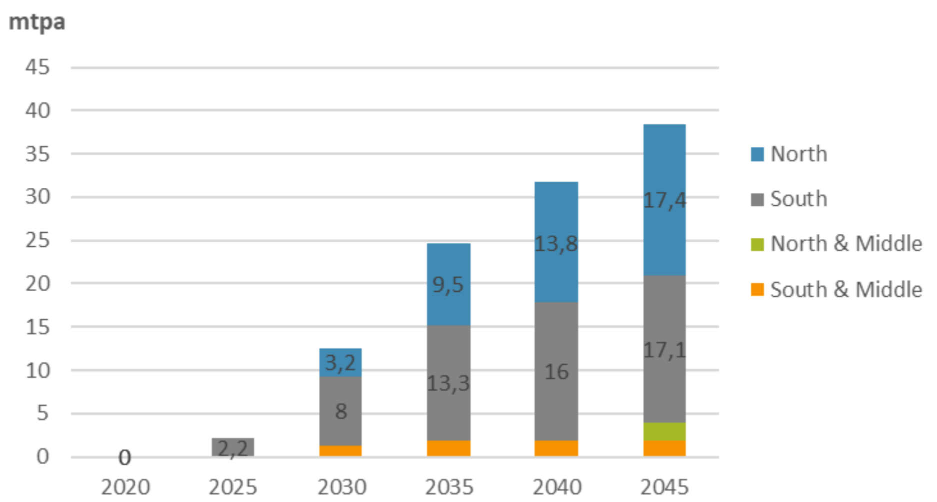
Table 2.7. Viet Nam's Installed Capacity Target, by Select Fuel

	Revised PDP 7, %	Draft PDP 8, %	
	2030	2030	2045
Installed capacity (MW)	N.A.	137,662	276,601
Coal	43	27	18
Gas	15	21	25
Hydro	17	18	9
Renewable	21	29	44

Source: Ohno and Tsunematsu (2021).

LNG demand is expected to rise significantly in the next decade to reach the capacity target. In a high-demand scenario, LNG demand will increase from 2.2 mtpa in 2025 to 38.4 mtpa in 2045. In terms of the demand region, while the south area will start as the largest demand area in 2025, the north area will catch up and become the largest demand area, with 17.4 million tonnes per year in 2045. Currently, most LNG projects are in the south, but the north is expected to have significant demand expansion, providing opportunities for potential investors.

Figure 2.6. Viet Nam's LNG Demand in High Scenario, 2020–2045



Source: IEEJ–ERIA Workshop, 'A Flexible LNG Market and Promotion of Investment in ASEAN – Under a New Era of Price Volatility and Energy Transition', Saigon Asset Management's presentation on LNG development in Viet Nam.

The growth potential of LNG demand in Viet Nam has attracted various investors to develop LNG-to-power projects. The Revised PDP 7 approved 10 LNG-to-power projects (Table 2.8). This will require significant upfront investments to build infrastructure across the LNG-to-power chain, and the government is looking for investors and sponsors for foreign capital and expertise.

The US's engagement

Many sponsors are US companies in these approved projects, demonstrating the US's interest in Viet Nam's LNG market. The possible reasons are geopolitical and market concerns. Geopolitically speaking, it is of interest to the US to diversify markets for its LNG exports because of the tension between the US and China. There are still significant volumes of the US-produced LNG under construction that need to secure outlets regarding market concerns.

Under the Indo-Pacific Strategy and Asia EDGE (Enhancing Development and Growth through Energy) initiative, the US government is currently working closely with US industries to advocate the development of LNG infrastructure projects in Viet Nam. To be more engaged in the LNG-to-power projects in Viet Nam, in addition to supplying LNG, US companies also engage in financing and constructing power plants.

In October 2019, the US-based power company AES received approval for a combined cycle gas turbine (CCGT) power plant in Son My 2 with 2.2 GW from the Viet Nam government (NS Energy, 2019). In October 2020, AES and PV Gas signed a joint venture to develop Son My LNG terminal during the Third Indo-Pacific Business Forum (Pham, 2020b).

Chan May LNG is also a US–Viet Nam joint venture with an initial capacity of 2.4 GW in phase 1, expected to be operational in 2024, and a total capacity of 4 GW for the entire plant scheduled to be operational in 2027. Chan May LNG is 60% owned by US investors and 40% by Vietnamese investors. The project company has stated that the project has considerable support from the US government as US LNG suppliers still have LNG volumes to market. In addition, several institutions have shown interest in financing the projects, including the US Exim Bank, the US International Development Finance Corporation, and the International Finance Corporation (Vu, 2020).

The US-headquartered Delta Offshore Energy is developing the Bac Lieu LNG-to-power project. The project consists of a 3 mtpa floating LNG import terminal and a 3.2 GW combined cycle power plant in the Mekong Delta in Bac Lieu province. The LNG is expected to be imported from the US, which will help balance the US–Viet Nam trade. In January 2021, Delta Offshore Energy signed a 25-year power purchase agreement (PPA) with EVN, which is the final major step of the LNG-to-power project. The company claims that this is the first 100% privately funded major project in Viet Nam (Pekic, 2021; Pham, 2020c).

Table 2.8. Viet Nam's LNG-to-Power Project

Project Name	Location	Capacity (MW)	Expected COD	Project Sponsor	Note
Hiep Phuoc	HCMC	1,200	2022	Hai Linh	Power plant only. LNG is imported through Hai Linh LNG terminal in Vung Tau.
Son My 1 (BOT)	Binh Thuan	2,000	2027	EDF[a], Sojitz, Pacific Group, Kyushu Electric Power	Power plant only. LNG is imported via Son My LNG Terminal.
Son My 2 (BOT)	Binh Thuan	2,200	2026–2027	AES	Power plant only. LNG is imported via Son My LNG terminal.
Nhon Trach 3,4	Dong Nai	1,300–1,760	2023–2024	PV Power	Power plant only. LNG is imported via Thi Vai LNG terminal.
Ca Na (Phase 1)	Binh Thuan	1,500	2025–2026	It is an EVN project. Ongoing investor selection process	Fully integrated project with import terminal, storage, regasification plants, and power plant.
Bac Lieu	Bac Lieu	3,200	2024–2027	Delta Offshore Energy	Fully integrated project with FSRU, pipelines, and power plant.

Long Son	Ba Ria - Vung Tau	3,600–4,500	2025–2026	EVN GENCO3, Mitsubishi, GE, Pacific Corporation, Vietnam's Viet Nam's Power Engineering Consulting Joint Stock Company 2 (PECC 2) and TTC Group	Fully integrated project with FSRU, pipelines, and power plant.
Long An	Long An	3,000	2025-2026	Vina Capital & GS Energy	Power plant only. LNG is imported via Thi Vai LNG terminal.
Quang Ninh	Quang Ninh	1,500	2026–2027	Proposed by PV Power & Colavi (Viet Nam) & Tokyo Gas & Marubeni	Fully integrated project with FSRU, pipelines, and power plant.
Hai Lang	Quang Tri	1,500	2026–2027	Proposed by T&T Group	Fully integrated project with FSRU, pipelines, and power plant.

[a] The EDF Group of France.
Source: IEEJ–ERIA Workshop, 'A Flexible LNG Market and Promotion of Investment in ASEAN – Under a New Era of Price Volatility and Energy Transition', Saigon Asset Management's presentation on LNG development in Viet Nam.

Table 2.9. Viet Nam's Newly Proposed LNG-to-Power Project

Project Name	Location	Capacity (MW)	Expected COD[a]	Project Sponsor	Note
Khanh Hoa Petrolimex Terminal Project	Khanh Hoa	4 plants with a combined capacity of 6,000 MW	N.A.	Proposed by Vietnam National Petroleum Group (Petrolimex)	The complex has 180,000 m^3 LNG storage facility. Petrolimex signed an agreement with Eneos in 2019.
Ca Mau 3	Ca Mau	1,500	2026–2027	PV Power	N.A.
Chan May LNG	Thua Thien Hue	2,400–4,000	2024 (Phase 1) 2027 (entire plant)	US–Viet Nam joint venture	A complex with an LNG terminal and storage facilities
Hai Phong	Hai Phong	4,000	N.A.	ExxonMobil and JERA	LNG import facilities and gas-fired power plants

[a] C operations date.
Source: *ET Energy World* (2020).

Challenges in Viet Nam

As much as LNG is a promising business in Viet Nam as the government supports LNG-to-power, various challenges, along with the development of the LNG value chain, exist. The potential challenges are listed as follows:

Technical aspect
The construction and design of LNG terminals, regasification units, storage, and pipeline network to power plants are capital-intensive and require knowledge and experience. As a new member of the LNG importing club, Viet Nam needs to establish technical and safety regulations and standards on the design and operation of LNG storage and onshore gas recycling systems.

Legal framework
Draft PDP 8 is under review, and further amendments are required. Thus, even though LNG demand is expected to grow significantly, there are still uncertainties before the policy direction is confirmed. Furthermore, foreign investors are looking for a stable and clear legal and regulatory framework to evaluate the risks.

Historically, state-owned enterprises dominated the power market in Viet Nam. However, the government has recognised the need to liberalise the power market and has implemented reforms in phases for the power market. The ongoing regulatory reform plays a vital role in the LNG market development of Viet Nam.

Funding guarantees
The upfront investment cost coupled with a long development timeline poses a risk for investors. The financing of LNG terminal and power plant needs to be underpinned by agreements: the terminal use agreement with the terminal owner and the PPA with a power company, such as EVN. Given the interconnected nature of these commercial agreements, a government guarantee and undertaking (GGU) for foreign investors and financial institutions are essential. Currently, no GGU exists in Viet Nam, which would potentially hamper the project development.

LNG affordability
The biggest challenge of the LNG-to-power project is that there is no output pricing or offtake guarantee mechanism for LNG-fired power plants despite LNG-fired power plant investors having requested such arrangements. As a result, LNG could turn out to be costly relative to electricity tariffs in Viet Nam remaining relatively low.

The price of input LNG fuel accounts for 80% to 90% of the output price of power, meaning that the profit margin for LNG-fired power plant investors may not be material enough for them to weather such risks. In addition, the government has been unable to provide any guarantee. As such, some financial institutions refuse to extend loans to investors to implement LNG projects.

For LNG-to-power to develop, an offtake mechanism must ensure the purchase of LNG power output or investors must be ready to assume risks even without any pricing guarantee or offtake mechanism.

The current situation in Viet Nam is that all LNG power plant projects are still projects existing only on paper because no capital disbursement has been made. Moreover, construction has not begun due to such LNG power plant projects failing to secure output channels.

2.3. Indonesia

Background

Indonesia has considerable energy resources, including oil, natural gas, and renewable energy resources. Most oil and gas resources are in western and eastern Indonesia. Recently completed and proposed LNG projects include Dongi-Senoro, Tangguh, and Abadi Masela, all in eastern Indonesia.

Oil and coal are the dominant fuel, accounting for 70% of the country's TPES in 2019. Indonesia's TPES was 236.8 Mtoe in 2019, and coal accounted for the largest share of 36%, followed by oil 34% and gas 18%. The final energy consumption was 147 Mtoe in 2019, with oil representing the largest share of 33%, followed by renewables (25%), coal (17%), electricity (16%), and gas (9%).

To promote the development priorities for domestic energy resources, the government announced the National Energy Policy (NEP) in 2014 to set targets to encourage coal and gas use while minimising the use of oil. NEP's target of transforming primary energy supply is as follows (IAEA, 2018):

Table 2.10. Primary Energy Supply Target in Indonesia

	2019 TPES	2025 target	2050 target
Oil	34%	<25%	<20%
Coal	36%	>30%	>25%
Gas	18%	>22%	>24%
Low-carbon energy sources and renewables	13%	>23%	>31%

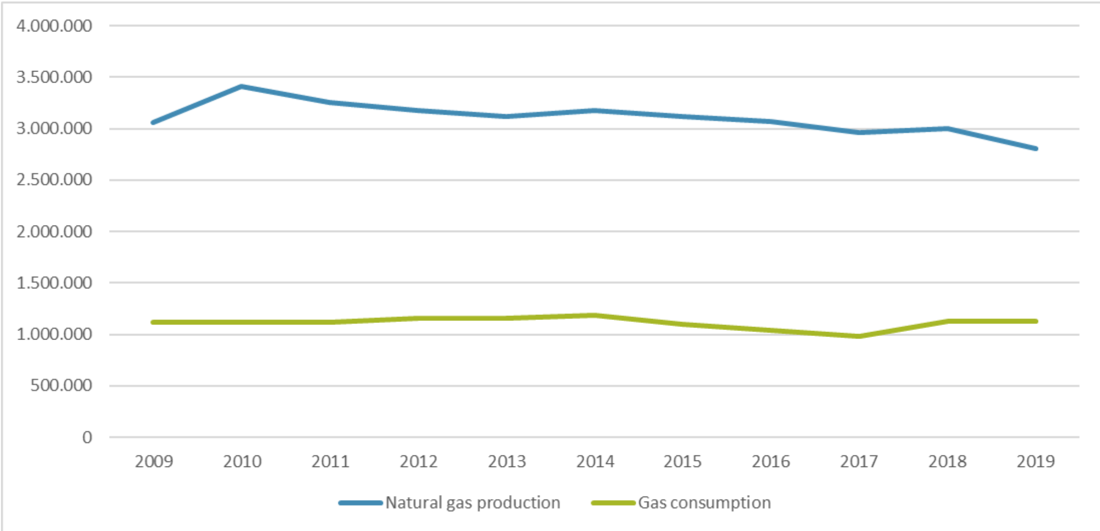
Sources: MEMR (2020), APERC (2019b).

Natural gas production and LNG trade

Indonesia's large natural gas reserves are in Badak in East Kalimantan, Corridor in South Sumatra, the Natuna Sea, the Makassar Strait, the Masela Block in Maluku, and Bintuni Bay in Papua. Smaller offshore gas reserves are in West and East Java (APERC, 2019a). With abundant natural gas resources, Indonesia started exporting LNG from Tangguh, Bintuni Bay, Papua in 2009. It is the seventh-largest LNG exporter in the world as of 2020. The country exported 15 million tonnes of LNG, with 4.2% of the world's LNG exports in 2020 (GIIGNL, 2021).

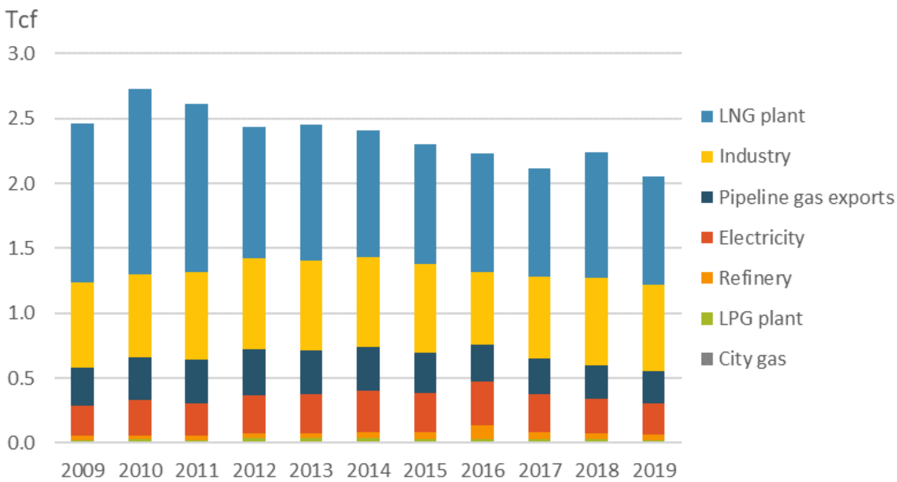
The country's natural gas production stands at around 3 Tcf, but it has started decreasing since 2014 because the gas fields are depleting. As a result, production declined by 12% from 3.2 Tcf in 2014 to 2.8 Tcf in 2019 (Figure 2.6).

Figure 2.7. Natural Gas Production in Indonesia, 2009–2019



Source: MEMR (2020).

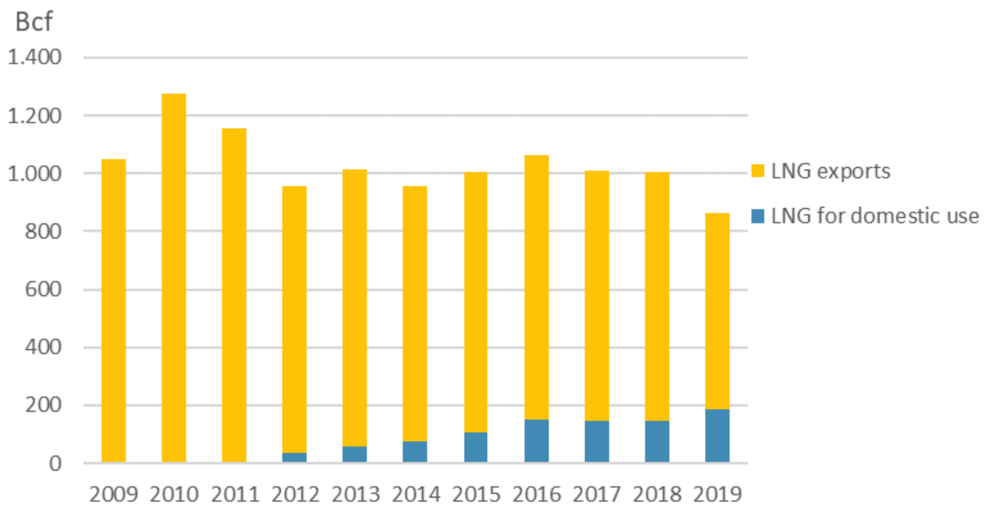
Figure 2.8. Natural Gas Demand, by Use in Indonesia, 2009–2019



Source: MEMR (2020).

In 2019, 41% of the gas production was liquefied at two LNG plants, and 32% was consumed in the industry sector. Pipeline gas exports and the power sector accounted for 12% each, refinery 2%, and LPG plant 1% (Figure 2.7). In 1977, all the LNG produced was exported to other countries (Pradipta, 2016). However, as domestic demand for gas grew, Indonesia had started to 'import' (from East Kalimantan to West Java) LNG domestically since 2012. Domestic LNG demand grew almost fourfold from 37 Bcf to 185 Bcf between 2012 and 2019. The growing trend of domestic LNG demand is expected to continue while the LNG exports (into international markets) declined by 58% from 2010 to 2019 (Figure 2.9).

Figure 2.9. LNG Production, by Use, 2009–2019



Source: MEMR (2020).

Recent regulatory framework for gas market

Gas price adjustment to create more gas demand

To further stimulate gas demand in the country, the Indonesian government announced in 2020 the capping of gas prices for strategic industries and power plants. The gas price should be US$6 per Million British thermal units (MBtu) at the plant gate for strategic industries: fertiliser, petrochemical, oleochemical, steel, ceramic, glass, and gloves latex industries. For power plants, the gas prices should be adjusted variably for each allocation between US$4–US$8/MBtu, with a price formula linked mainly to Indonesian crude price.[17]

The adjustment is aimed at the upstream gas price and the transportation and midstream costs. It is translated into the upstream gas price of US$4–US$7/MBtu. Prices are adjusted so that more gas demand could be boosted while not economically jeopardising the upstream companies.

[17] IEEJ–IEF Workshop, 'The Global Future of Natural Gas in a Low Carbon World – The Future of Natural Gas in Southeast Asia', Pertamina's presentation material.

The government's subsidy for this gas price comes from the government's share in the related gas fields. Pertamina is assigned to supply gas to industries with regulated gas prices. In 2020, a total volume of 2,601 billion British thermal unit per day (BBtud) gas prices was adjusted: almost half is provided to the strategic industries with 1,505 BBtud of gas and 1,396 BBtud of gas for power plants.

The gas price adjustment has positively impacted the strategic industries as it has encouraged and stimulated the production growth of these industries, especially for those heavily relying on gas as their feedstock or fuel, such as the fertiliser industry.

GHG reduction target by 2030
The Indonesian government has committed to reducing GHG emissions up to 29% in 2030 by promoting cleaner fossil fuel, renewable energy, and energy efficiency increase, including the use of natural gas in generating power (UNFCCC, n.d.). The gas price adjustment for strategic industries and power plants is also a measure to promote more use of natural gas.

Infrastructure development

Natural gas plays an essential role in Indonesia. It serves as a fuel for power generation and feedstock for the petrochemical industry and provides economic revenue through LNG exports. Indonesia has three LNG liquefaction plants: Bontang (11.5 mtpa capacity), Tangguh (7.6 mtpa), and Donggi-Senoro (2.0 mtpa) (GIIGNL, 2021). The Bontang project is 100% owned by the Indonesian government, while the other two projects have overseas investors involved. The Tangguh LNG Phase 2 expansion is currently under construction and is expected to operate by mid-2022 after construction delays caused by the COVID-19 pandemic.

As domestic gas demand is projected to increase and domestic gas production decreases, the country becomes a potential market for its LNG production from the existing LNG infrastructure. However, Indonesia has over 14,000 islands, making it difficult to have an integrated natural gas pipeline network. Therefore, to deliver more gas to remote areas and islands, some innovative solutions were introduced in the country, including small-scale LNG, ISO tanks and trucks, and LNG-to-power.

Small-scale LNG terminals
In 2014, the government issued the National Gas Policy Road Map 2014–2030, which proposed to develop small-scale LNG infrastructure to supply gas to the small islands in eastern Indonesia. Small-scale LNG terminals offer relatively low initial investment requirements with a smaller capacity than traditional LNG receiving terminals (ERIA, 2021b). According to the International Gas Union criteria, small-scale LNG has a liquefaction and regasification capacity of 0.05–1.0 mtpa and vessels with 60,000 m^3 or less.

The first small-scale LNG terminal is in Benoa Bali; it began operations in April 2016. The LNG terminal operated by Pelindo Energi Logistik intended to supply gas to a 250 MW power plant in Pesanggrahan, Bali, at 40 million standard cubic feet per day. The LNG facility consists of two main infrastructure elements: a floating regasification unit (FRU) and a floating storage unit

(FSU). LNG from Badak was stored at the FSU sent to the FRU, and then transported to the PLN power plant in Pesanggrahan. The total investment reported was US$500 million.

After 3 years of operations, the FSU and FRU were decommissioned and replaced with a new FSRU, Karunia Dewata, in December 2018. The new FSRU is equipped with four independent LNG tanks of a combined capacity of 26,000 m^3.

Another recent example is Pertamina's task to supply 55 small-scale gas-fired power plants across Indonesia, especially in the eastern part. It is challenging to build gas infrastructure and establish an LNG supply chain under the constraints of a landscape where most demands are far from the supply location.

This project is separated into three phases:

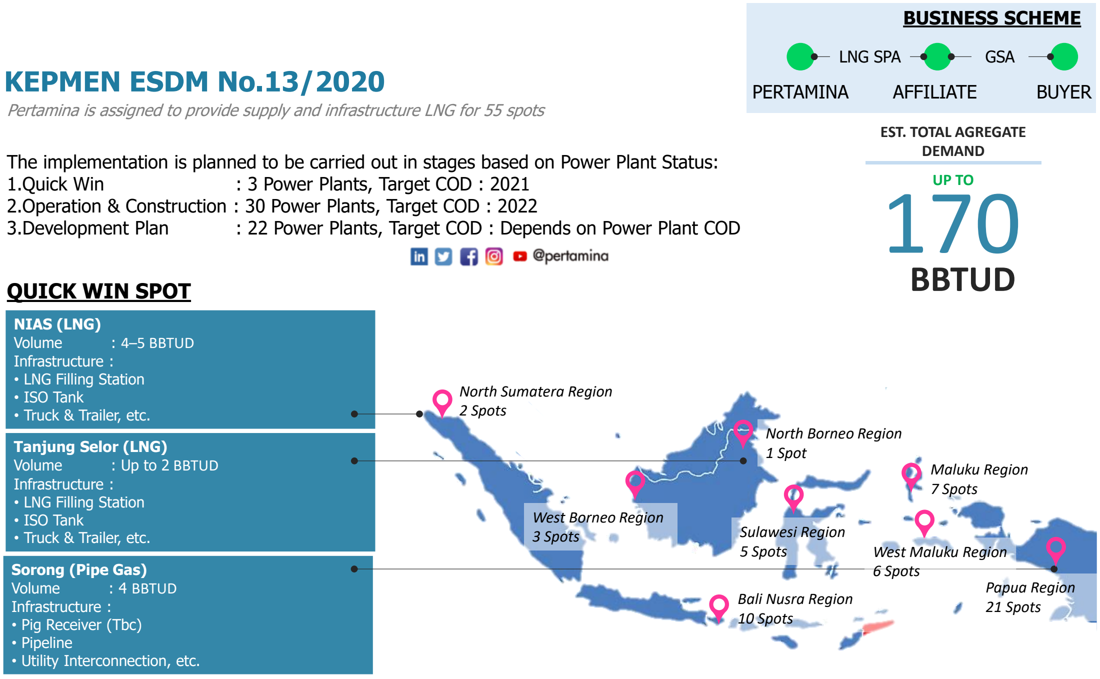
- Quick Win: 3 power plants, target COD[18] 2021
- Operation and construction: 30 power plants, target COD 2022
- Development plan: 22 power plants, target COD depending on power plant's COD

The first phase Quick Win project – which includes NIAS (LNG), Tanjung Selor (LNG), and Sorong (Pipe Gas) – are expected to operate in 2021. Pertamina will use ISO tanks, trucks and trailers, and other solutions to deliver LNG to demand areas in this phase.[19]

[18] Commercial operation date.

[19] IEEJ–IEF Workshop, 'The Global Future of Natural Gas in a Low Carbon World – The Future of Natural Gas in Southeast Asia', Pertamina's presentation material.

Figure 2.10. Pertamina's LNG Supply to 55 Spots



Source: IEEJ–IEF Workshop, 'The Global Future of Natural Gas in a Low Carbon World – The Future of Natural Gas in Southeast Asia', Pertamina's presentation material.

LNG-to-powership to provide electricity to off-grid villages

To reach more villages unconnected to the power grid, Indonesia adopts LNG-to-powership to provide electricity to those households from floating power plants. In 2015 and 2016, the country's state utility company PT PLN (Persero) signed five contracts with Turkey-based company Karpowership to deploy five powerships of combined capacity 1,000 MW for 5 years.

Karadeniz Powership Zeynep Sultan (125 MW), Onur Sultan (470 MW), Gökhan Bey (125 MW), Yasin Bey (125 MW), and Nezih Bey (37 MW) have been operating since 2016. Since 2018, Karadeniz Powership Onur Sultan in Medan has been operating with Indonesia's indigenous gas. Karpowership has been supplying 30% of North Sulawesi's, 55% of East Nusa Tenggara's, 80% of Ambon's, and 10% of Medan's total electricity needs (Karpowership, 2021).

In September 2020, Powership Zeynep Sultan, the project in Amurang, started transitioning to becoming Indonesia's first LNG-to-power project after successfully converting its first two dual-fuel engines (LNG Industry, 2020). The LNG is converted from liquid to gas via an FSRU operated by PT Sulawesi Regas Satu, a joint venture of PLN GG and PT Humpuss.

The electricity supply plan to 2026 that the government set out in 2019 says mobile power plants like this are expected to play a role in supplying electricity to rural and remote areas in a country where more than 2,500 villages are still not connected to the grid (Shell, 2019a).

2.4. Myanmar

Background

Like Indonesia, Myanmar is also endowed with natural resources such as oil, natural gas, coal, hydropower, and biomass. In 2018, Myanmar's TPES was 23.83 Mtoe, with biofuels and waste representing the dominant share of 46%, followed by oil (29%) and gas (17%). Power generation was 18.77 TWh in 2018, with hydropower (47%) and gas (44%) being the primary sources for power generation.

Myanmar has always been self-sufficient with gas until 2020. The country's natural gas production increased significantly from 6.8 Bcm to 21.2 Bcm between 2000 and 2016. However, as the gas field depleted, production had declined by 4% to 20.3 Bcm in 2018 from 2016. Myanmar began exporting pipeline gas to Thailand and China in 1999 and 2013, respectively. However, as Myanmar's gas field depletes, exports are also expected to decrease.

In recent years, the rapid growth of electricity demand and variability of hydropower output have resulted in significant power shortages in Myanmar. These have led the country to consider importing LNG as it is expected to be the fastest solution through utilising existing gas-fired units.

Government's LNG-to-power policy

In the Japan Producer-Consumer Conference 2020, Myanmar's Minister of Electricity and Energy announced that the country plans to build three LNG-powered plants of 3,000 MW to meet the growing electricity demand. One of the projects was awarded to a Japanese consortium in line with a government-to-government agreement. The strategy to use LNG for power generation allows Myanmar to construct new pipelines to carry regasified LNG to other parts of the country for industrial uses, especially for fertiliser, cement, and steel production. Myanmar is looking into expanding the LNG terminal facilities to have more LNG trades in the next stage, which will open more opportunities for LNG producers and exporters.[20]

Infrastructure development

Currently, Myanmar has one Thanlyin LNG FSU with a capacity of 0.5 mtpa. In May and June 2020, Myanmar received its first LNG cargoes from Petronas and officially joined the LNG importer club. The cargoes were shipped from Petronas LNG Complex in Bintulu on free-on-board basis (Bajic, 2020).

This FSU supplies LNG to an onshore regasification terminal, which feeds two power plants in Yangon, 400 MW Thaketa and 350 MW Thanlyin. This is the first facility where Myanmar uses imported LNG as a fuel source for power generation. The LNG-to-power project is financed, constructed, and operated by CNTIC VPower, a joint venture of China National Technical Import and Export Corporation and Hong Kong's VPower Group.

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[20] LNG Producer–Consumer Conference (2020), https://www.lng-conference.org/english/videos/ (17 September 2021).

LNG imported in Yangon is expected to supply another gas-fired power plant Thilawa, with a 1,250 MW capacity. It is still at the planning stage and is expected to come online by 2024.

Several LNG projects are also being developed. The Ahlone LNG power plant in Yangon is Myanmar's first LNG project involving an onshore LNG terminal and regasification unit. The PPA was signed in January 2021 between Electric Power Generation Enterprise under the Ministry of Electricity and Energy and TTCL Power Myanmar Co. The project is expected to be completed in early 2024 and is one of the 3,000 MW LNG-to-power projects (Htwe, 2021).

In May 2021, the Myanmar Investment Commission (MIC) approved 15 projects, including a US$2.5 billion LNG-to-power project, which would be the biggest single investment since the military takeover on 1 February 2021. MIC did not reveal details in the press release, but some sources said the approved LNG project is likely to be the Chinese-backed Mee Lin Gyaing power project in the country's Irrawaddy Delta, judging from the project cost. China signed a letter of intent with Myanmar's then-government National League for Democracy in 2020 to speed up the project development under the Belt and Road Initiative agreement.

The Mee Lin Gyaing project with a capacity of 1,390 MW is developed jointly by Yunnan Provincial Energy Investment Group Co. Ltd., UREC, Zhefu Holding Group Co. Ltd., and Supreme Group. Completion is expected in 2023; 35% of the power produced will be distributed to the Ayeyarwady Region, the rest to Yangon via the national grid.

However, the military coup is still ongoing in Myanmar, and the economy is unstable. The United Nations (UN) even has warned in April 2021 that Myanmar is approaching economic collapse (UN News, 2021). Therefore, whether these LNG-to-power projects could develop on time depends on how and when the coup ends.