Istituto Affari Internazionali

Natural Gas in South-east Asia: Key Trends and Long-term Outlook

by Luca Franza and Beni Suryadi

ABSTRACT

Given the increasing gas demand and declining domestic supply, countries in South-east Asia are bracing themselves to become net gas importers and are studying ways to enhance their security of supply. LNG will be the preferred source of gas, thanks to its flexibility and widespread availability at competitive prices in global markets. However, concerns related to excessive gas import dependency might reduce appetite for additional gas usage in South-east Asia. This could mean that coal would have a larger role, which is bad news for climate change. Countries in the ASEAN region need policies to achieve balanced, reliable, secure and cost-effective energy supply, a pre-requisite for the region's ambitious economic development plans. A combination of solid local policies, investment by international players in the region and stability in global gas markets would enable gas to play a positive role in South-east Asia, which is a fast-growing region and an increasingly important catalyst of global energy market developments.

South-east Asia | ASEAN | Natural gas

keywords

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Natural Gas in South-east Asia: Key Trends and Long-term Outlook

by Luca Franza and Beni Suryadi*

Introduction

Along with China and India, Southeast Asia is contributing to shifting the centre of gravity of global energy markets towards Asia, thanks to its high rates of GDP and energy demand growth. After contracting due to the pandemic in 2020, the GDP of the Association of Southeast Asian Nations (ASEAN) region is expected to rebound by 6 per cent in 2021, while the pre-covid annual GDP growth rate surpassed 5 per cent.[1] Regional energy demand has expanded by more than two and a half times since 1990, one of the highest growth rates in the world, and is expected to continue expanding in future. The region has a population of almost 650 million people and a combined GDP of approximately 3 trillion US dollars.[2] To be sure, the region is very diverse, with countries at various stages of economic development and with very different energy mixes that largely reflect their different domestic resource endowment. While some are net energy importers, others are net energy exporters, hosting significant gas, coal, and oil resources. Some of the net exporters play an important role in global energy markets, like Indonesia and Vietnam in coal and Indonesia, Malaysia, and Brunei Darussalam in gas.

Gas has indeed proved key to satisfying ASEAN's booming electricity demand and energy needs in industry, especially in the 2000s, while its consumption growth has slowed down in the 2010s. Gas consumption growth is expected to continue in the next decades, but there is significant uncertainty with regard to the scale and timing of such growth. Per capita electricity consumption remains below

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[1] Statista, *Gross Domestic Product (GDP) of the ASEAN Countries from 2010 to 2020*, https://www.statista.com/statistics/796245/gdp-of-the-asean-countries; GlobalData, *ASEAN Economies Poised for Robust Recovery with 6% Real GDP Growth in 2021, Says GlobalData*, 15 February 2021, https://www.globaldata.com/?p=54698.

[2] World Bank Data, 2020.

* Luca Franza is Head of the Energy, Climate and Resources Programme at the Istituto Affari Internazionali (IAI). Beni Suryadi is Manager of Power, Fossil Fuel, Alternative Energy and Storage at the ASEAN Centre for Energy (ACE). The authors are grateful to Adhityo Gilang Bhaskoro for his contribution. The authors would also like to express gratitude to Akbar Dwi Wahyono, Gabriella Ienanto and Rifa Fadilla for their support.

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the world average, leaving significant room for expansion. There is a clear trend towards convergence with global per capita electricity consumption rates as living standards are improving. This is one of the single most important drivers behind expected gas demand growth.

The region has significant gas reserves, particularly in Indonesia, Malaysia, Brunei, Myanmar, Thailand, and Vietnam. However, production in mature legacy fields is declining and only few commercially viable new gas findings have been made in the last decade. Some of the region's gas reserves are hard to recover and low global gas prices are an obstacle to their exploitation. The picture sketched above – essentially one of growing demand and declining production – increases the likelihood that Southeast Asia will turn from being a net gas exporter to being a net importer on aggregate. This is reflected for instance in the 6th ASEAN Energy Outlook, which estimates that ASEAN demand will surpass production in 2024.[3] This rests on a number of assumptions and, as said above, significant uncertainty as to timing and scale of transformations in the regional supply and demand balance exists. Moreover, while the region as a whole might very well turn into a net importer, some countries within the region will maintain their net exporter status for longer. Besides, the fact that some new fields will be developed in South-east Asia might (temporarily) alter the downward trajectory in the net export curve in some countries.

The fact that Southeast Asia could turn into a net importing region opens up new challenges and opportunities for various stakeholders. Countries in the region will have to keep an eye on their energy import bill, trade balance and security of supply as they become net importers. This calls for new strategies and policies. Besides, local energy companies will have to think on how to adapt their business model to the new conjuncture, perhaps acquiring portfolio positions to gain the required flexibility and maximise the value of their vertically integrated positions across local gas value chains. Finally, international oil and gas companies could be interested in capturing new opportunities offered by Southeast Asia as a market outlet for their growing liquefied natural gas (LNG) portfolios. They could establish new partnerships with governments in the region, which will likely be in need of their integration in local markets and reliability as gas suppliers but also of their know-how and capital to build or operate new import infrastructure and soften the domestic gas production decline by investing in the upstream.

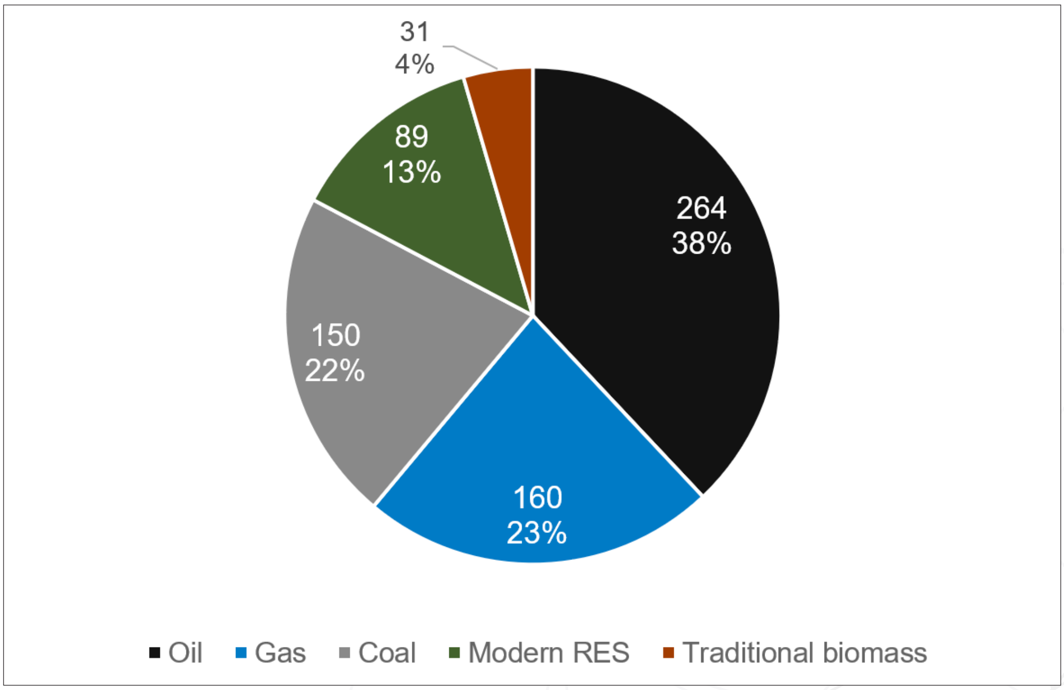
1. The regional energy mix and the current role of gas

Gas plays an important role in the regional energy mix, being the second most consumed fuel in Southeast Asia. With consumption totalling 178 billion cubic

[3] ASEAN Centre for Energy (ACE), *The 6th ASEAN Energy Outlook 2017-2040*, Jakarta, ACE, 2020, p. 52, https://aseanenergy.org/?p=6373.

meters (bcm) in 2019, gas accounts for 23 per cent of the primary energy mix.[4] It is also the top fuel in power generation. In 2019, the total primary energy supply (TPES) of the ASEAN region was estimated to be around 694 million tons of oil equivalent (Mtoe) in total.[5] Fossil fuels contributed for 83 per cent. Oil remains the dominant fuel, with demand currently standing at 5.2 million barrels per day (mb/d), corresponding to a 38 per cent share in the primary energy mix. In the last two decades, however, there has been a steady shift away from oil towards natural gas and coal, especially in the power sector. One of the drivers has been decline in domestic oil production and the incentive to maximise profitable oil exports rather than using oil for domestic power generation. Coal use has been rising significantly, particularly in the last decade, and now accounts for 22 per cent of TPES. Modern renewable energy sources (RES) such as hydro, geothermal, wind, and solar photovoltaic) currently account for 13 per cent of the primary energy mix. Efforts are underway to boost their utilisation further to reduce local air pollution, limit global warming and reduce energy import dependency. The remaining share of TPES (4 per cent) is covered by traditional biomass. While the use of biomass has fallen in the last decade, this source of energy is still being burnt for cooking in less developed areas.

Figure 1 | ASEAN total primary energy supply (2019) in Mtoe and percentage



Source: ASEAN Energy Database.

[4] ASEAN Energy Database.

[5] Ibid.

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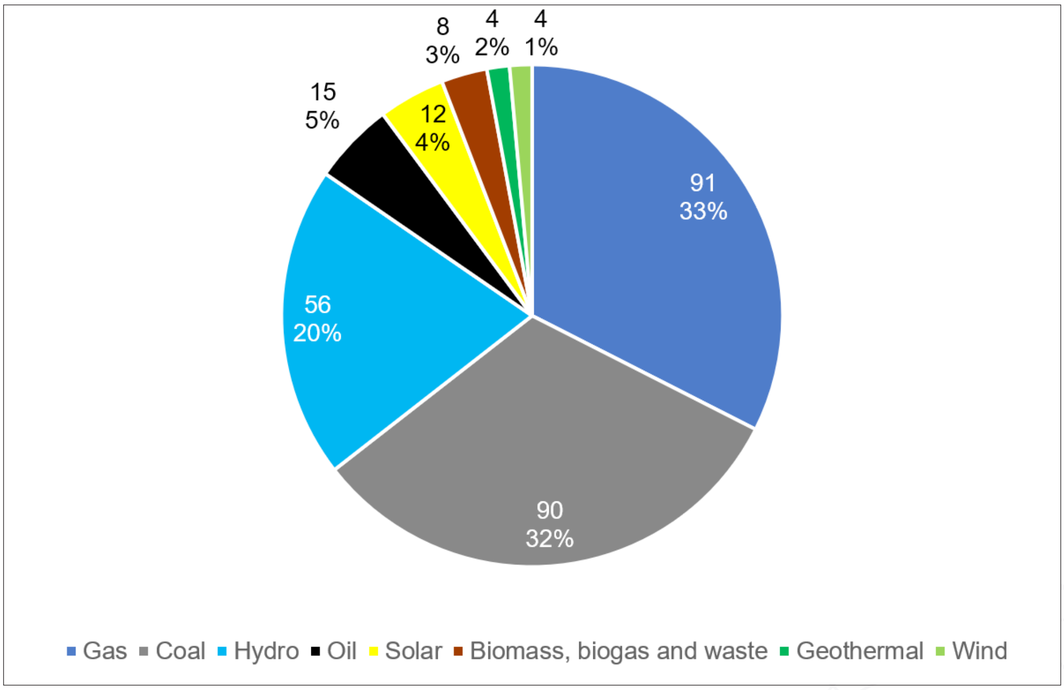
Approximately 280 gigawatts (GW) of power generation capacity is installed in the ASEAN region, generating about 1,132 terawatt-hours (TWh) in 2019 (see Figures 2 and 3).[6] Thermal generation capacity accounted for 70 per cent of total generation capacity, with gas accounting for 33 per cent, coal for 32 per cent and oil for 5 per cent. Hydropower capacity stood at 20 per cent, the remaining share being covered by other renewable energy sources (RES). Coal, gas and hydro together generated three quarters of electricity in the ASEAN region in 2019, while oil was barely burnt to produce power, leaving quite a lot of oil-fired power generation capacity unutilised.

Figure 2 | Installed electric capacity in ASEAN (2019) in GW and percentages



Source: ASEAN Energy Database.

Total final energy consumption (TFEC) was estimated to be around 414 Mtoe in 2019 (equal to around 60 per cent of TPES), with the industrial sector absorbing the largest share (156 Mtoe or 38 per cent of the TFEC), followed by transportation (148 Mtoe or 36 per cent), the residential sector (68 Mtoe or 16 per cent), and finally the commercial sector and agriculture. Oil accounted for 47 per cent of final energy consumption, followed by electricity at 21 per cent.[7]

[6] Ibid.
[7] Ibid.

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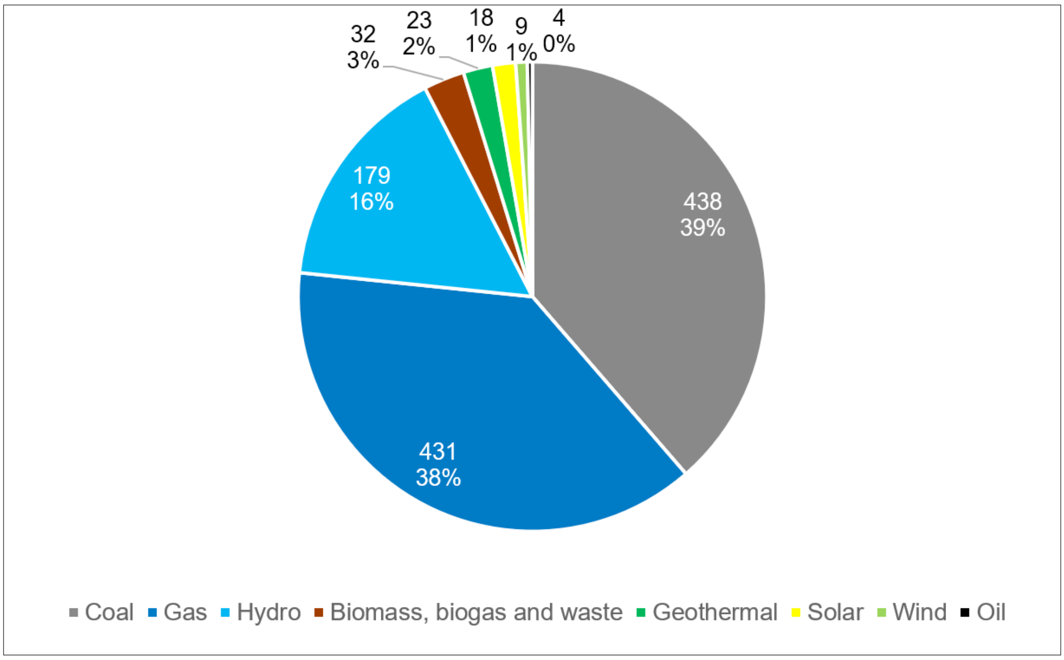
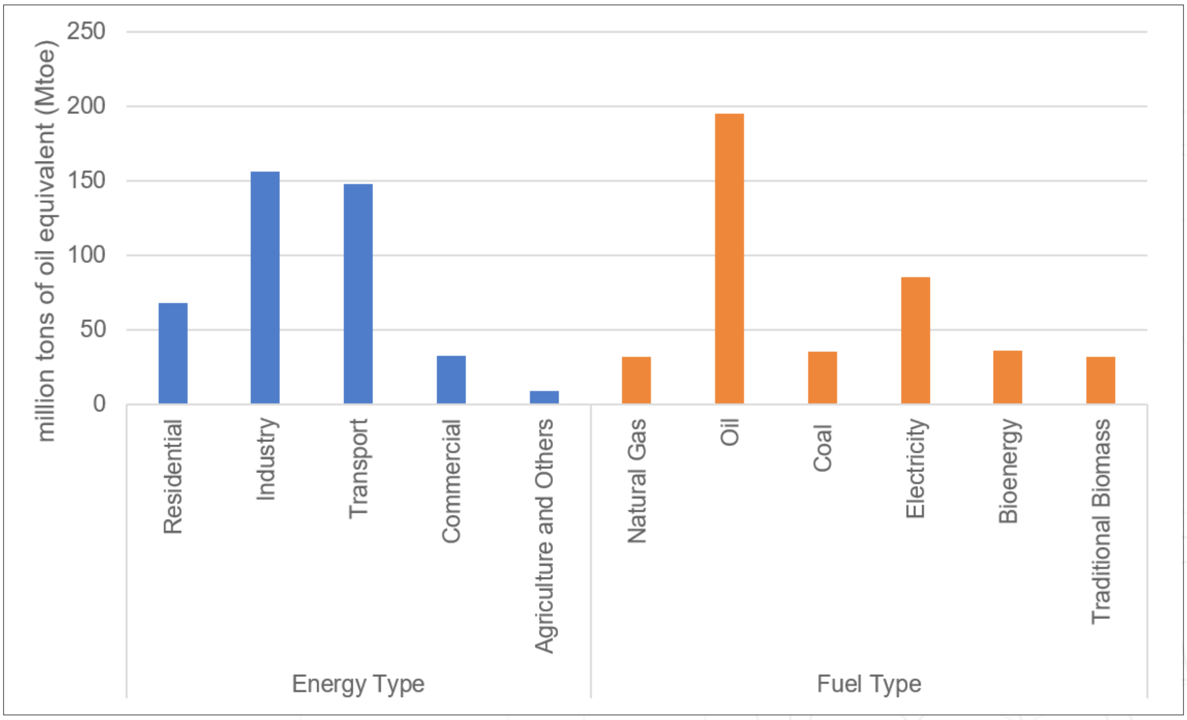
Figure 3 | Power generation in ASEAN (2019) in TWh and percentages



Source: ASEAN Energy Database.

Figure 4 | ASEAN total final consumption of energy by sector and energy carrier



Source: ASEAN Energy Database.

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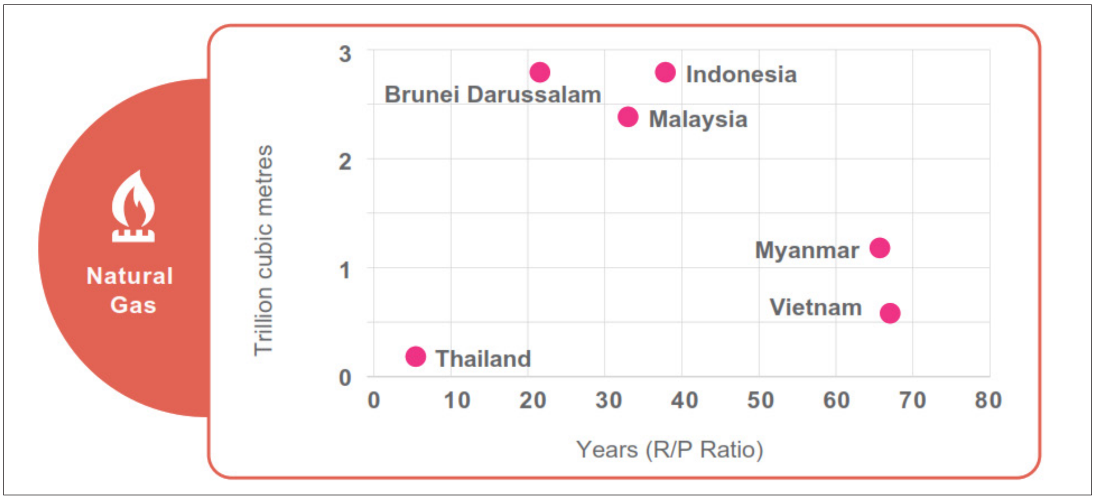
Indonesia and Brunei have the largest proven reserves of gas with roughly similar amounts of around 2.8 trillion cubic meters (tcm) each, followed by Malaysia (2.4 tcm), Myanmar (1.2 tcm), Vietnam (0.6 tcm), and Thailand 0.2 (tcm). According to projections on the R/P ratio by the ASEAN Energy Outlook 2020 (Figure 5), Vietnam has gas reserves for 68 years, closely followed by Myanmar with reserves for 66 years, and then by Indonesia (38 years), Malaysia (33 years), Brunei Darussalam (21 years) and Thailand (10 years). In short, this points to a solid reserve base.

Figure 5 | Proven natural gas reserves and production ratios, 2018



Source: ASEAN Energy Database.

However, not all of these reserves will eventually be monetised. A substantial share of gas found in the region is either unconventional, deep-water, or characterised by high CO2 or hydrogen sulphide content. Depending on local pricing formulae and future global gas market fundamentals, imported gas might be cheaper than domestically produced gas in some cases. Imported gas might also be more readily available, whereas, given the long lead time of investments, the development of domestic gas would require a strong insight on long-term supply and demand balances, which is not always easy to obtain sufficiently in advance.

2. The regional outlook for gas

The sixth ASEAN Energy Outlook report contains three scenarios: the Baseline scenario, the ASEAN member states target scenario (ATS), and the APAEC target scenario (APS). The Baseline scenario assumes that energy demand growth continues on a business-as-usual basis in the region. The ATS scenario assumes that each ASEAN member state fully achieves its respective national targets on energy efficiency and renewable energy ambition. In APS, the most climate ambitious scenario, ASEAN countries collectively attain the agreed 2025 regional targets of 23 per cent renewable energy share in TPES and 30 per cent reduction in

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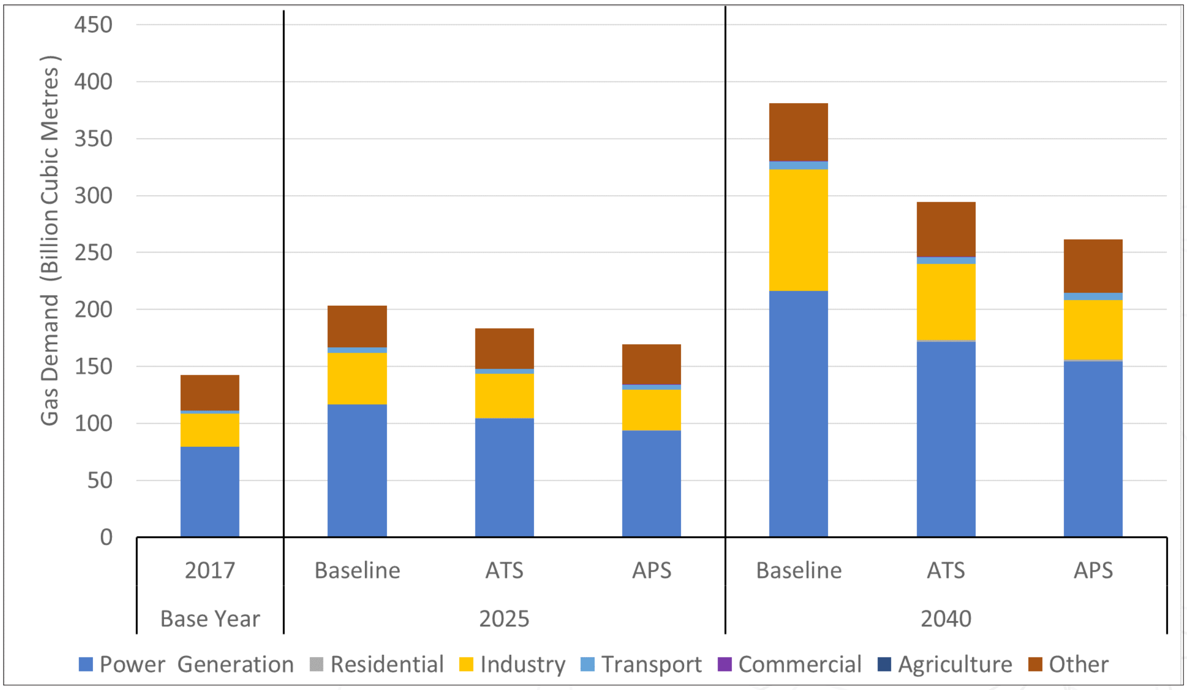
energy intensity compared to 2005.

The highest gas demand is expected in the Baseline scenario (203 bcm by 2025 and 381 bcm by 2040). In ATS, gas demand is projected to reach 183 bcm in 2025 and 294 bcm in 2040. In the most climate ambitious scenario, gas demand is estimated to reach 169 bcm in 2025 and 261 bcm in 2040. In the Baseline scenario, the share of gas in power generation is projected to reach 27 per cent by 2025 (about 117 bcm) and 22 per cent by 2040 (216 bcm). Gas is expected to face increasing competition from renewables and coal-fired power projects, as key member countries seek to rebalance their fuel mix in order to maintain security of supply, reacting to an upstream gas resource depletion trend. Electricity demand in the ASEAN region has grown by an average of 5.7 per cent annually in the last two decades, increasing from about 380 TW/h in 2000 to over 970 TW/h in 2017. The Gas Advocacy White Paper (GAWP) projects that this growth is likely to be sustained at an average rate of about 5.6 per cent per annum in the period between 2020 and 2030. Consequently, peak demand for electricity within ASEAN is estimated to reach 240 GW by 2030 and 305 GW by 2035 from 133 GW in 2020. This implies average power capacity additions of 13 GW per annum in 2020–2030, increasing to 15 GW per annum between 2030 and 2040.[8]

Figure 6 | ASEAN gas demand outlook



Source: ACE, *The 6th ASEAN Energy Outlook 2017-2040*, cit.

[8] ACE, *The 6th ASEAN Energy Outlook 2017-2040*, cit.

The relatively lower growth in gas demand expected in APS is due to the higher efficiency expectations that reduce the overall power sector and industrial demand, as shown in Figure 6. While gas demand in those two sectors is decreasing, other sectors show minimal change relative to other scenarios. The "others" sector in the figure refers to the use of gas in oil and gas production, energy sector own use and other non-energy use (e.g. feedstock) Gas demand is expected to grow in the long term in all of the ASEAN countries where gas is already abundantly consumed today, driven by the local gas-intensive industry and power sector needs.

3. Highlights by country

3.1 Brunei

Brunei is a historically large oil and gas producer and exporter. Natural gas is mostly produced in association with oil at the Southwest Ampa and Champion fields. Brunei has a liquefaction terminal at Lumut with a capacity of 9.8 bcm/y, from which it has traditionally supplied LNG to Japan and South Korea.[9] Similarly to other South-east Asian hydrocarbon exporters, Brunei has been able to diversify its export outlets in the 2010s by starting to sell LNG cargoes to India, China and other growing Asian importers. Its exports have however been steadily declining due to maturing production in historical fields and higher domestic consumption.

The country relies on oil and gas revenues for about 60 per cent of its GDP and about 90 per cent of its exports and government revenues.[10] Lower oil and gas prices since late 2014 have negatively impacted on its economy. The government is trying to simultaneously revive investment in oil and gas by seeking partnerships with international oil companies (IOCs) and diversify its economy by stimulating other industries. The country's policy priority has long been that of finding a balance between gas exports and domestic gas use. Brunei Darussalam currently prioritises domestic gas use, particularly in electricity, where gas plays an important role. To avoid using all gas domestically, however, the government is promoting alternative sources of energy as well as energy efficiency.

Brunei Darussalam's demand for natural gas amounted to 3.9 bcm in 2019.[11] Unlike other countries, where gas demand has contracted in 2020 due to covid-19, consumption increased substantially in 2020 (+10 per cent),[12] driven by the need for feedstock in the newly opened petrochemical manufacturing unit at Hengyi's PMB refinery. Brunei's natural gas consumption is expected to continue rising

[9] US Energy Information Administration (EIA), "Brunei", in *EIA Analysis*, March 2017, https://www.eia.gov/international/analysis/country/BRN.

[10] Ibid.

[11] ASEAN Energy Database.

[12] Ibid.

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across the coming decade, although at a slower pace than in 2020. Greater demand for gas will originate from the growing petrochemical industry and expanding gas-powered electricity production. However, given the small size of the country and its population, absolute growth in gas consumption will remain small. In the latter sector, there are modest downside risks to gas demand posed by the government's renewable energy expansion campaign and plans to cut energy intensity by 45 per cent by 2035.[13]

3.2 Cambodia

Cambodia's long-standing policy priority is to meet its fast-growing energy demand at an affordable price and reduce dependency on imported coal, diesel and heavy fuel oil. In fact, the country has one of the smallest yet fastest-growing economies in the ASEAN region. Installed power capacity increased by almost 15 times in the last 15 years, creating the expectation that the country will actually exceed its target to further expand capacity by 25 per cent by 2025.[14] Hydropower is currently the largest source of electricity, followed by coal and oil. Natural gas consumption in the country is virtually inexistent. Cambodia imported its first LNG volumes in January 2020 through small-scale tanks supplied by China's CNOOC and benchmarked to the domestic price of Chinese LNG transported by trucks. This was CNOOC's first small-scale gas supply scheme outside of China and one of the few gas projects in the context of the Belt and Road Initiative.

Cambodia also has plans to build a floating storage and regasification unit (FSRU) to import larger LNG volumes in future and construct an internal pipeline and trucking network, but these plans have been delayed by the covid-19 pandemic. Like other South-east Asian developing countries, Cambodia's LNG development plan mostly revolves around the interdependent realisation of an FSRU and a gas-fired power plant. Lack of progress in the construction of the power plant would thus delay the construction of the FSRU and vice versa. The first phase of the infrastructural development plan, which has stalled, targets the laying of a pipeline between Kompong Som Bay and Phnom Penh. After the abovementioned pilot project relying on the Chinese small-scale tanks, which supplied a handful of upscale houses in the country's capital, Cambodia Natural Gas Corp aims to deploy LNG in hotels and restaurants and only at a later stage in the industrial and power sectors. The Phnom Penh and Preah Sihanouk provinces will be the first areas of the country where LNG will be rolled out.

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[13] Brunei Darussalam Prime Minister's Office-Energy Department, *Brunei Energy Report Whitepaper*, 2014, https://www.esci-ksp.org/?p=9954.

[14] Eric Yep, "Analysis: COVID-19 Delays Cambodia's LNG Ambitions after Initial Imports from China", in *S&P Global*, 1 October 2020, https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/100120-analysis-covid-19-delays-cambodias-lng-ambitions-after-initial-imports-from-china.

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3.3 Indonesia

Indonesia reached a peak production of 86 bcm of gas in 2010, after which output gradually declined to today's level of 68 bcm/y.[15] While historical fields are depleting, new projects have been launched and more will be launched in the next years, including Eni's Jangkrik, started in 2017 i.e. just three years after the investment decision, as well as Eni's Merakes, currently under development and further supported by a fresh discovery at Merakes East and further resource potential at Eni's West Ganal block, in the East Kalimantan basin. Another contribution to further production will come from Repsol's Sakakemang finding south of the island of Sumatra. There is also significant resource potential in East Natuna, as well as in gas plays located close to the planned Abadi LNG terminal, but uncertainty there is greater. New volumes will allow Indonesian gas production to gain strength in the late 2020s, possibly breaking the 2010 production record reaching 90 bcm/y.[16] After 2030, however, production is set to decline in default of significant investment (that would have to be allocated earlier in time) in high-risk, high-cost deepwater or coalbed methane extraction. The development of those reserves would need a special conjuncture of high prices and strong policy support and reform by the Indonesian government in order to attract the necessary finances and technical know-how from the private sector.

Recent signs of a growing role of the state in the sector point in a different direction. A complex entanglement of policy priorities creates inertia in the Indonesian gas sector. The government has in fact set a maximum price for domestically produced gas, which is in itself positive for gas demand growth. At the same time, producers of gas have a domestic market obligation (DMO) to sell at least 25 per cent of their output on the Indonesian market, a measure introduced by the government to prevent the entire output from being exported to international markets (which are more lucrative). Yet the domestic price cap clearly encourages producers to seek alternative outlets outside of Indonesia beyond the DMO quota, which induces the government to rely on the national oil and gas company Pertamina to prevent shortages in the domestic market, also considering that demand is growing (as explained below). A significant growth in the role of Pertamina to the detriment of international oil and gas companies, however, would complicate access to much needed international capital and know-how.

After booming in the 1990s and 2000s, Indonesian gas consumption has been stable at around 40–45 bcm/y in the last decade, with 36 per cent of gas being used in power generation (where gas has a 25 per cent share), another 36 per cent for energy production in industrial applications, and the remaining share as feedstock in industry or in energy sector operations.[17]

[15] ASEAN Energy Database.

[16] Mike Fulwood and Martin Lambert (eds), "Emerging Asia LNG Demand", in *OIES Papers*, No. NG 162 (September 2020), p. 31-32, https://www.oxfordenergy.org/?p=40863.

[17] Ibid., p. 33.

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Domestic production and consumption of coal have increased substantially since 2008–2009, on the back of skyrocketing power generation needs. Coal is a threat not only to gas demand growth potential but also to local air quality, the local environment, and global warming. Similarly to other emerging Asian economies, however, it will be challenging to discourage the use of a domestic and cheap energy source in a country with a fast-growing population and economy. It should furthermore be highlighted that coal is also a source of export revenues for Indonesia. Renewables use will also expand, with the national electricity company PLN planning to develop a combined capacity of 14 GW over the next decade.[18] Radically different outlooks are available for Indonesian gas demand, but there seems to be a higher concentration of consensus around relatively conservative estimates of 70–100 bcm by 2040.[19] This would still entail a significant growth of 30–70 bcm from today's consumption levels. Growth is expected to pick up especially in the second part of the 2020s, driven by booming electricity consumption and, to an extent, higher industrial use to produce fertilizers, metals and ceramics.

Indonesia exports part of its gas to Singapore and Malaysia by pipeline, but is mostly known around the world as a large LNG supplier. After peaking in 1999, Indonesian LNG exports have declined and currently amount to 20 bcm/y approximately. Japan, South Korea and Taiwan have traditionally absorbed the bulk of Indonesia's LNG exports, but China has started importing LNG from Indonesia in 2009, becoming the country's top LNG buyer. A peculiarity of Indonesia is that it uses LNG to transport gas internally, from Central-Eastern islands like Sulawesi, Kalimantan and New Guinea (where gas is produced) to Central-Western islands and particularly Java and Bali (where more gas is consumed). As a future development, small-scale LNG in remote areas of the country such as Papua, Maluku, Nusa Tenggara, as well as islands like Sulawesi and Kalimantan is being explored. Another peculiarity is that in spite of being a net LNG exporter, Indonesia also imports LNG since 2014. This is reflected in the fact that Indonesia is planning both regasification (West Java FSRU) and liquefaction (Tangguh Train 3, Abadi LNG, Sengkang) terminals. The national oil and gas company Pertamina has signed purchase contracts with LNG shippers and portfolio players such as Woodside, Cheniere, Total, Chevron, Eni and Anadarko. Depending on developments in the Indonesian supply and demand balance, these volumes could either cover Indonesian gas consumption or be re-exported to other countries, providing Pertamina with flexibility and enabling it to become a portfolio player. All in all, however, abovementioned trends in supply and consumption point to a strong likelihood that Indonesia will become a net importer in the late 2030s.

[18] ASEAN Energy Database.

[19] International Energy Agency (IEA), *Southeast Asia Energy Outlook 2017. World Energy Outlook Special Report*, October 2017; APEC Energy Working Group, *APEC Energy Demand and Supply Outlook*, 7th ed., Vol. II, May 2019, https://www.apec.org/Publications/2019/05/APEC-Energy-Demand-and-Supply-Outlook-7th-Edition---Volume-II.

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3.4 Laos

Laos is a landlocked country and has the second smallest economy in the ASEAN region after that of Brunei Darussalam. In the last two decades the country has experienced the fastest economic growth in the ASEAN region and a substantial rise in foreign investments driven by timber, copper and hydro. However, the country is still characterised by a lower level of development than most other South-east Asian nations. Laos remains largely rural and is in need of investments to upgrade its infrastructure, including roads. In energy, the country seeks to reduce petroleum import dependency by developing indigenous energy resources such as hydro and coal and by capitalizing on electricity exports as a way to generate foreign exchange. Hydro currently accounts for up to 85 per cent of power production, while natural gas is not used at all in the country. The country is still characterised by a widespread use of slash-and-burn agriculture and wood fuel, which aggravates deforestation. LPG could greatly help to improve access to modern energy sources in cooking.[20]

According to the Lao PDR Energy Outlook 2020, electricity generation will increase at an average growth rate of 5.8 per cent per year until 2040, when it will reach 70 TWh.[21] Hydropower is expected to grow significantly and remain dominant by supplying 77 per cent of the country's electricity in 2040. The opening of the Hongsa coal-fired power plant, which burns domestic lignite, has helped in terms of energy trade balance but is clearly negative from an environmental perspective. What is more, all of the electricity produced at Hongsa is actually exported to Thailand and therefore does not contribute to expanding energy access in Laos. Coal-fired power generation is projected to further increase in future and reach 22 per cent of power production in 2040, with emerging domestic consumption in addition to exports. Natural gas, which is not given a specific role by policies and whose development is complicated by the lack of domestic resources in Laos as well as its landlocked position, would contribute to diversifying the country's energy mix, reducing its carbon footprint, and supporting energy access and social-economic development.

3.5 Malaysia

Malaysia has historically been a large gas producer, with the bulk of the country's production taking place offshore Sarawak and feeding the 30 bcm/y Bintulu liquefaction terminal. New discoveries have been made since 2010 and production has subsequently been launched in new fields, making up for production decline

[20] Lao Institute for Renewable Energies (LIRE), *Lao PDR Market Assessment. Sector Mapping*, USAID, July 2013, https://www.cleancookingalliance.org/resources_files/laos-market-assessment-sector-mapping.pdf.

[21] Laos Ministry of Energy and Mines and Economic Research Institute for ASEAN and East Asia (ERIA), *Lao PDR Energy Outlook 2020*, Jakarta, ERIA, February 2020, p. 81, https://www.eria.org/publications/lao-pdr-energy-outlook-2020.

in mature reservoirs. Aggregate output is expected to fall as a result of a decline in production in Peninsular Malaysia and stable production off Sarawak. Newly discovered fields hold interesting production potential, but high CO2 and hydrogen sulphite content make them expensive to exploit. Gas subsidies have been gradually phased out by the government, and a market-based pricing approach has been adopted, which might provide support to new upstream activities. At the same time, the government is implementing other energy policies to achieve security of supply and diversification, in light of decreasing domestic production.

Malaysian gas consumption amounted to 38 bcm in 2019. Gas plays a key role in power generation, where it competes head-to-head with coal. After a strong increase in the 1990s and 2000s, largely driven by oil-to-gas switching in power generation, growth in gas demand has significantly slowed down in the last decade mostly thanks to lower gas use in energy sector operations, while the use of gas as a feedstock in industry has kept on increasing. Malaysia introduced a system of regulated third-party access to natural gas infrastructure in 2016, which is regarded as positive for future gas demand because greater downstream competition is expected to reduce end-user prices. However, prospects for future gas consumption in the power sector will largely depend on coal use, which has grown significantly and is expected to further expand until approximately 2030 before flattening out as a result of growing carbon prices and climate targets.[22] The government is also pushing for RES deployment through the National Green Technology Policy and is promoting energy efficiency policies. Their potential repercussions on future gas consumption are however difficult to determine.

Similarly to Indonesia, Malaysia is a net exporter of gas but also imports some small gas volumes – notably piped gas from Indonesia and LNG from Brunei Darussalam and Australia. Malaysia has two regasification terminals at Lekas and Pengerang, where downstream integration ensures that LNG is consumed in a petrochemical and refining cluster. Policy favours LNG-to-power schemes. The country had to start imports because of gas shortages provoked by a combination of stagnating domestic production and consumption growth in 2000s and 2010s, as well as the presence of contractual commitments to export. This makes Malaysia reluctant to renew its legacy export contracts at current conditions. Significant take-or-pay volumes of 15 bcm/y will be unlocked in the next decade in default of export contract renewals.

Like in neighbouring Indonesia, there is also intra-Malaysian LNG trade as gas mostly originates from Borneo while the bulk of demand is in Peninsular Malaysia. Again like Indonesia, sales to the traditional outlets of Japan and South Korea have gradually given way to exports to China, the world's fastest growing LNG import market. Malaysia also has international pipeline connections to Thailand, Singapore and Indonesia. Apart from Bintulu, Malaysia also has a floating liquefaction facility and is planning a new one. In line with the demand expectations sketched above,

22 Mike Fulwood and Martin Lambert (eds), "Emerging Asia LNG Demand", cit.

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LNG import needs will grow especially after 2030, when the country might very well become a net importer.

3.6 Myanmar

Reflecting a lower level of economic and industrial development than other South-east Asian countries, gas consumption in Myanmar remains modest (5 bcm/y) relative to its population (54 million).[23] Pricing issues, supply constraints and poor infrastructure have curbed gas consumption so far. However, the country is developing fast and gas consumption is expected to soar, doubling or tripling by 2030 depending on the scenario. However, the political situation arisen after the recent coup creates uncertainty that extends to the economic and energy realm. It will thus be necessary to reassess all forecasts contained in this section based on how long instability lasts. Similar to other countries in South-east Asia, the power sector absorbs a very high share (70 per cent) of gas demand.[24] The shares of gas used in transportation as compressed natural gas (CNG) and in energy sector operations are relatively high, while marginal volumes are used in industry, notably for the production of fertilisers.

In addition to gas, a key source of electricity is hydro, the consumption of which has increased substantially in the 2000s and 2010s. The country's electrification campaign has been and will continue to be a major driver of increased gas consumption. Power production has more than tripled since 2000. The electrification rate has subsequently improved – reaching 50 per cent – but is still well below the regional average. The government plans to provide its population with universal energy access by 2030 with an intermediate target of 75 per cent electrification by 2025.[25] Installed power generation capacity will have to triple again to reach the 2030 target. At a policy level, the government aims to turn to both gas and coal to address frequent power cuts in major cities, while the process of restructuring and corporatization initiated in the power distribution sector should help improving performance and efficiency. The government is also aiming to introduce rural electrification schemes hinging on the use of renewable energy.

Myanmar has been a significant gas producer since the 1990s. Gas has mainly been produced in the historical Yadana and Yetagun offshore fields, while production has more recently been sustained by the development of the Shwe and Zawtika fields. Production has been stable between 2005 and 2013 at around 10–12 bcm/y, increasing to almost 20 bcm/y after 2014. Due to the natural depletion rate of mature fields, production is expected to decline quickly until 2030, when it will be

[23] ASEAN Energy Database.

[24] Ibid.

[25] Myanmar National Electrification Program (NEP), *Roadmap and Investment Prospectus. Final Roadmap and Investment Prospectus*, September 2014, https://www.seforall.org/sites/default/files/Myanmar_IP_EN_Released.pdf.

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only one fourth of what it is today.[26] Recently, production from the Yetagun field has been shut down invoking a *force majeure* clause in relation to the political crisis, further constraining gas availability in the country. This points to a very rapid production decline, which might only partly be offset by new developments as potential to increase domestic production is estimated to be limited.

This suggests that gas imports will have to increase. In anticipation of the emerging supply-demand gap, the country, which is tied to contractual commitments to export piped gas, has planned to start importing LNG. At present, Myanmar exports two thirds of its gas production. Thailand has been the historical buyer of Burmese gas and China started importing piped gas from Northern Myanmar in 2014. Due to corrosion, the North-South pipeline within Myanmar is not in use. The 2017 Natural Gas Master Plan foresaw four LNG terminals at Kyauk Phyu, Mee Long Gyiang, Yangon and Kanbauk.[27] An important obstacle to their realisation has been that the gas-fired power plants that should have underpinned investment in each terminal struggled to secure power purchase agreements (PPAs) for their output.

However, the government sped up LNG-to-power developments after widespread power cuts in May 2019. Finally, after two years of delay, Myanmar received its first LNG cargoes in June 2020 from Petronas Malaysia, carried by VPower-CNTIC. Three PPAs for LNG-fired power plants at Thaketa (400 MW), Thanlyin (350 MW), and Kyauk Phyu (150 MW) were inked in June 2020 with a duration of 60 months each.[28] The cost of imported LNG has been made lower than Myanmar's own piped gas exports to encourage LNG imports, which – as mentioned – are urgently needed for power production.

Pipeline exports are expected to continue at current levels until 2025, halving after that date, while LNG imports are projected to reach 5–10 bcm/y by 2030.[29] To accommodate these volumes, not only will all of the currently proposed LNG developments have to be built, but additional onshore terminals or FSRUs will also be needed. There is interest by multilateral organizations and foreign companies in exploring the possibility of developing FSRUs in Myanmar. China is also active in this business through the Belt and Road Initiative (which for instance financed the Kyauk Phyu LNG-to-power scheme).

3.7 The Philippines

The Philippines' total gas demand was around 4.1 bcm in 2019 and fell by 20 per cent in 2020 due to covid-19,[30] matching the supply decrease at the Malampaya

[26] Mike Fulwood and Martin Lambert (eds), "Emerging Asia LNG Demand", cit.

[27] Yoshikazu Kobayashi and Phoumin Han (eds), *Natural Gas Master Plan for Myanmar*, Jakarta, ERIA, December 2018, https://www.eria.org/publications/natural-gas-master-plan-for-myanmar.

[28] ASEAN Energy Database.

[29] Mike Fulwood and Martin Lambert (eds), "Emerging Asia LNG Demand", cit.

[30] ASEAN Energy Database.

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offshore field, the country's main source of natural gas. The Philippines displays peculiar patterns as more than 97 per cent of all gas production is consumed in the power sector. What is more, all gas-fired power plants are located around Batangas, within less than 20 km from the landfall of the pipeline that carries gas from the Malampaya field. This points to an unusual concentration and intertwinement between consumption (for power production) and (local) production. A pipeline from Batangas to Manila (the "BatMan pipeline") and various other potential pipeline projects have been on the table for years but have not yet seen the light. Eventually, their construction will depend on the balance between expected gas consumption, production, and LNG imports. Because nearly all gas is consumed in the power sector, the outlook for natural gas consumption is very much dependent on developments in that sector.

The substantial increase in Filipino power needs has so far mostly been fulfilled by coal, the consumption of which has doubled in just a decade. On the other hand, natural gas demand has stagnated after initial growth linked to the development of Malampaya. According to the list of plants commissioned by the government in the main island of Luzon in 2019, more than 80 per cent of new capacity will be coal-fired.[31] Increased coal consumption would clearly have negative effects on local air quality and greenhouse gas emissions. Using gas instead of coal would be advantageous from an environmental perspective, but prospects of falling domestic production after 2022 discourage the government from supporting gas use. Legislation, which hinges on the Electric Power Industry Reform Act (EPIRA), tends to favour coal in power generation. The current policies notably prevent project developers from gaining adequate visibility on future revenue streams, which would be necessary to underpin investment on new power plants and on either pipelines or LNG terminals.

The Philippines should import LNG from the early to mid-2020s to offset expected declines in domestic gas production. The Department of Energy's Gas Circular issued in late 2017 emphasized the limitations of domestic gas resources and recognised the need to develop natural gas infrastructure including an LNG terminal for imports.[32] While the country has no operational regasification terminals yet, there is a project in Quezon (with a capacity of 4 bcm/y) and three projects in Batangas (with total capacity of 12.9 bcm/y).[33] These have been approved by the Department of Energy. In addition, there are six other proposed LNG projects across the Philippines. Even so, the path towards LNG is not easy due to market disruptions and continuous project delays. Without policy support, LNG terminal projects might not be bankable. In default of sufficient gas volumes because of decline in production from Malampaya and delays in (or cancellation of)

[31] Mike Fulwood and Martin Lambert (eds), "Emerging Asia LNG Demand", cit.

[32] Philippine Department of Energy, *Department Circular No. DC2017-11-0012: Rules and Regulations Governing the Philippine Downstream Natural Gas Industry*, 12 April 2017, https://www.doe.gov.ph/sites/default/files/pdf/issuances/dc2017-11-0012.pdf.

[33] ASEAN Energy Database.

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the construction of LNG terminals, the existing gas-fired power plants will be used for peak shaving rather than for baseload production. Gas-fired power plants could then either be decommissioned or converted to burn oil products for peak shaving when Malampaya gas production comes to a complete halt. On the contrary, if the government decides to back LNG terminals, gas consumption has the potential to increase significantly, also beyond power. The situation in The Philippines is illustrative of the importance of supportive policies for greater natural gas use in South-east Asia, which would clearly benefit the environment relative to scenarios where larger coal volumes are used.

3.8 Singapore

Gas consumption in Singapore was 13.8 bcm in 2019 and is estimated to have contracted by 9 per cent in 2020 due to covid-19 lockdowns.[34] Demand has increased substantially in the last two decades, considering that it amounted to only 2 bcm/y until the 2000s. Relative to the world and the regional average, power generation accounts for an exceptionally high share of gas demand, with 85 per cent of gas being used for power generation and 94 per cent of electricity being produced with natural gas. Residential energy consumption is expected to rise in the next two decades, while forecasts for industrial and commercial demand are much less bullish. Future gas demand is going to be shaped by this development. In fact, all available scenarios estimate that gas demand will increase mostly to satisfy rising electricity demand towards 2030 and 2040, although figures differ significantly. The range of expected gas demand growth to 2030 is between +1.3 bcm/y and +3.2 bcm/y and the range of expected growth to 2040 is between +1.7 bcm/y and +5.3 bcm/y relative to 2017.[35] The single most important factor of uncertainty is energy efficiency, where significant progress would greatly reduce gas needs. Another important development to watch is installation of new solar capacity, which enjoys strong policy support.

Singapore has no domestically produced gas and is instead reliant on pipeline imports from Malaysia and Indonesia and LNG imports via its onshore terminal SLNG. The Singaporean government invested in SLNG to increase energy security in anticipation of falling piped gas import volume availability and with a view to position Singapore as an Asian LNG trading and bunkering hub (a role that the country already plays in oil). Today, LNG imports are around 3–4 bcm/y. LNG mostly comes from Australia and is mostly supplied by the Shell portfolio. While available LNG import capacity is sufficient to satisfy current gas demand, there are plans to expand SLNG by another 5 bcm/y and build a new regasification terminal

[34] Ibid.

[35] Singapore Energy Market Authority, *Singapore Electricity Market Outlook 2018*, 30 October 2018, https://www.ema.gov.sg/semo.aspx; Loi Tian Sheng Allan and Jacqueline Yujia Tao, "Singapore Country Report", in Shigeru Kimura and Han Phoumin (eds), *Energy Outlook and Energy Saving Potential in East Asia 2016*, Jakarta, ERIA, June 2016, p. 297-322, https://www.eria.org/publications/energy-outlook-and-energy-saving-potential-in-east-asia-2016; APEC Energy Working Group, *APEC Energy Demand and Supply Outlook*, 7th ed., Vol. II, cit.

at Changi. This is because Singaporean LNG imports are expected to increase significantly in the next years (up to an additional 10 bcm/y by the mid-2020s relative to today)[36] on the back of growing domestic demand and an expected decrease in piped gas imports from Malaysia and Indonesia, which are unlikely to renew their export contracts with Singapore due to their own rising domestic needs.

Singapore's electricity market, where most gas is consumed, has been liberalized with the development of a competitive wholesale electricity market, the National Electricity Market of Singapore (NEMS) in 2003. Gas markets are also liberalized and transportation is separate from import, shipping and retail. The Gas Network Code provides open and non-discriminatory access to the pipeline network, while an independent regulator, the Energy Market Authority (EMA), ensures that rules are respected. Neither gas nor power prices are subsidized. Since the beginning of 2018, interested parties have been able to import spot LNG cargos, which is subject to a market-wide cap of 10 per cent of the country's long-term gas supplies. The Singapore Maritime Port Authority recently announced that it is providing co-funding grants for the construction of two LNG bunkering vessels, which are slated for delivery in 2020. SLNG is modifying one of the jetties to accommodate smaller vessels (with capacities ranging from 2,000 to 10,000 m^3) as part of its efforts to develop LNG bunkering and small-scale LNG.

3.9 Thailand

Current Thai gas consumption amounts to approximately 50 bcm/y. It rose substantially in the 1990s and 2000s driven by oil-to-gas switching in the power sector and growing power demand, and then stabilised in the 2010s. Most gas is used to produce electricity (30 bcm/y), a sector where gas has a share of 70 per cent.[37] Relative to other countries, fairly large shares of gas are consumed or lost in conversion in energy sector operations and in the transportation sector. Gas demand at present is being negatively impacted by the covid-19 pandemic as economic activities, particularly those pertaining to tourism and exports, are shut or forced to operate at limited capacity. Gas demand is estimated to have contracted by 4 per cent in 2020, as slight increases in household consumption failed to offset larger declines in gas consumption in other sectors. Gas demand however is expected to return to 2019 levels in 2022, as underlying fundamentals are positive.

In the longer term, developments in power demand will be a key driver for future gas consumption. Scenarios radically differ from one another, with one of the few certainties being that power demand will go up. The official Thai Power Development Plan aims at increasing the share of renewables from 5 per cent

[36] Ibid.

[37] ASEAN Energy Database.

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today to 20 per cent in the late 2030s. This would lead to a decrease in the share of both gas and coal. However, as power demand is expected to increase, this would still translate into an increase in gas consumption in the power sector, stabilising at around 45 bcm/y between 2030 and 2040. Total gas demand would then be around 60 bcm/y. Other scenarios are less positive and project stagnating gas use in the power sector in the next two decades. The single most important factor that determines the difference between outlooks is coal consumption, which in the most bullish scenario is projected to quadruple in the next thirty years.

Thai gas production is mostly offshore, originating from the joint development area with Malaysia in the Gulf of Thailand. Thailand's offshore gas reserves have halved since 2005, providing a clear signal of the forthcoming decline in domestic production. Seeing domestic production declining and consumption growing (or – more recently – remaining stable at relatively high levels), Thailand started to import piped gas from Myanmar and, since 2011, LNG from other countries. Pipeline imports from Myanmar have plateaued, while LNG imports have steadily grown and averaged 5 bcm/y in the last three years. After initially relying on spot cargoes, Thailand signed a number of LNG contracts with portfolio players. At the moment, LNG mostly comes from Qatar, followed by Nigeria and Malaysia. PTTEP, the Thai national oil company (NOC), is also trying to position itself as a portfolio player and acquired upstream interests, notably in Mozambique. The contract with Myanmar ends in 2025 and is unlikely to be renewed with the same terms as Myanmar is prioritizing gas for domestic use. Thailand has a heavy build-out of LNG regasification terminals ahead to replace declining piped gas import volumes. The existing Map Ta Phut regasification terminal's capacity will be increased by 5 bcm/y and new FSRUs will be built to accommodate higher imports. Policies are in place to establish market-based price signals to keep gas demand under control, given growing exposure to higher priced LNG imports. Energy efficiency measures are also being pursued to limit gas demand growth.[38] Policy also aims at maximising domestic gas production, ensuring effective and competitive LNG sourcing, building adequate infrastructure, and ensuring actual third-party access to infrastructure in addition to foreseeing it on paper.[39] In a sign of competition and as part of efforts to achieve efficient LNG sourcing, the Thai electricity company EGAT is planning to import spot LNG through a dedicated terminal to serve its power plant rather than relying on the NOC as an intermediary.[40]

3.10 Vietnam

Vietnam has witnessed one of the most spectacular development pathways in Asia, with extraordinary GDP and population growth in the last three decades. As a result, energy demand has grown by almost ten times since 1990, also driven by

[38] Thailand Ministry of Energy, *Gas Plan*, 2015, http://www.eppo.go.th/index.php/th/plan-policy/tieb/gasplan.

[39] Ibid.

[40] Mike Fulwood and Martin Lambert (eds), "Emerging Asia LNG Demand", cit., p.

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rapid urbanisation that led to increased electrification and a higher use of gas to the detriment of biomass. Current gas consumption is around 10 bcm/y, 80 per cent of which is absorbed by the power sector.[41] Industrial energy consumption has also grown substantially but it has mostly been fulfilled by coal. In addition to coal and gas, hydropower and oil are also significant energy sources in Vietnam, with remarkable regional differences in use. The increase in coal demand is a source of concern due to its negative effects on local air quality and global warming.

According to ASEAN scenarios, gas demand will more than double and reach 24 bcm in 2029,[42] and other scenarios project gas demand in 2035 to be in a range comprised between 23 and 31 bcm.[43] This growth will be driven by an expansion in power demand, the highest in the ASEAN region with a Compound Annual Growth Rate (CAGR) of 8.5 per cent between 2013 and 2035. Domestic policies are expected to support gas, paving the way for more investments in gas-fired power projects. Indeed, the Vietnamese Power Development Plan (PDP) VIII (2021–2030) sets higher targets for gas-fired power generation. The new PDP is expected to incorporate an estimated 50 GW in gas-fired capacity to be developed over the 2021–2030 period through 20 LNG-to-power projects.[44]

Rising consumption incentivised the government to develop indigenous gas production with a view to keep import dependency under control. When growth in domestic gas production started to slow down, the country turned to another indigenous source, coal. However, coal use also outpaced production and Vietnam became a net coal importer. In addition to keeping import dependency in check, the government is also trying to match sources of supply – whether indigenous or imported – with specific demand centres because there is still no integrated pipeline infrastructure and building one from scratch would be expensive. At present, gas is mostly consumed in the south of the country, where it has historically been produced.

Additional gas production from new offshore gas projects and LNG imports will both be used to fulfil growing consumption, confirming the traditional approach to keep imports under control. Plans to boost domestic production hinge on an expansion of the existing Su Tu Trang field and on the development of new fields Ca Voi Xanh and Block B. Moreover, in mid-2020 Eni announced a significant gas discovery in the northern Block 114, offshore Song Hong Basin. In spite of this, LNG imports will almost certainly be needed to sustain demand growth in the southern

[41] ASEAN Energy Database.

[42] ACE, *The 6th ASEAN Energy Outlook 2017-2040*, cit.

[43] APEC Energy Working Group, *APEC Energy Demand and Supply Outlook*, 7th ed., Vol. II, cit.; Vietnam Electricity and Renewable Energy Authority (EREA) and Danish Energy Agency (DEA), *Vietnam Energy Outlook Report 2019*, October 2019, https://vietnam.um.dk/en/green-growth/vietnam-energy-outlook-report.

[44] Melissa Brown and Thu Vu, "IEEFA Report: Vietnam's New Power Development Plan Must Optimize Renewables and Avoid Fossil Fuel Lock-in", in *IEEFA Press Releases*, 22 September 2020, https://ieefa.org/?p=40384.

regions. Using the base case demand scenario and different production scenarios, the expected range of LNG imports in 2035 will be 6–16 bcm/y. In anticipation of growing LNG import needs, PetroVietnam has already signed some agreements from LNG imports in the early 2020s with Shell and Gazprom Marketing and Trading. A new regasification terminal, Thi Vai, is under construction, and another terminal, Son My, is planned to start operations in 2023. Both are linked to local power plants reflecting the abovementioned approach of matching supply and demand.

4. The way forward

Energy demand is expected to grow significantly in South-east Asia towards 2050, with a remarkable expansion potential for natural gas. This is particularly the case in power generation, followed by industry. Given the increasing gas demand and declining domestic supply, countries in the region are bracing themselves to become net gas importers and are studying ways to enhance their security of supply. LNG will be the preferred source of gas, thanks to its flexibility and widespread availability at competitive prices in global markets. However, concerns related to excessive gas import dependency might reduce appetite for additional gas usage in South-east Asia. This would be bad news for local air pollution and climate change as some countries in the region could increasingly resort to coal to fulfil their growing energy needs.

Whilst coal is an important source of low-cost baseload generation supply for ASEAN, overdependency on coal could turn out to be costly due to the risk of unmet demand as a result of the higher likelihood of project slippage deriving from siting constraints and stricter emission regulations. It would also clearly be negative from an environmental and public health perspective. To the contrary, promoting coal-to-gas switching while keeping gas consumption under control by implementing energy efficiency measures and promoting renewables would be beneficial for both the environment and the region's import bill. Gas is an important energy vector for South-east Asia as a flexible mid-merit generation source that enables keeping total system costs under control. Competitively priced LNG would enable extending the life of existing combined-cycle gas turbines (CCGTs) with expiring power purchasing agreements (PPAs), averting stranded asset costs. Gas in the form of small-scale LNG is also well-suited to deliver distributed solutions that can displace expensive oil-based fired units and abate potential network infrastructure constraints.

Countries in the ASEAN region need policies to achieve balanced, reliable, secure and cost-effective energy supply, a pre-requisite for the region's ambitious economic development plans. To this purpose, Power Development Plans (PDP) and Gas Master Plans (GMP) have recently been drafted in all ASEAN countries seeking to promote increased diversification in fuel and technology mix. Gas market reforms are needed to break monopolies, stimulate competition, avoid

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distortions and ensure third party access and ultimately deliver more competitive and affordable gas prices to end-users. Not all ASEAN markets are capable of supporting netback LNG market-based prices and progress on natural gas pricing reform has been slow. Gas pricing reforms could promote efficient use of gas, allow for a wider range of gas import sources, and facilitate the development of newer fields with higher wellhead costs.

Regional cooperation would be beneficial to the development of a robust and resilient gas sector in South-east Asia and some aspects of the gas market reforms sketched above could be jointly developed in a regional setting. Through the ASEAN Council for Petroleum (ASCOPE), ASEAN member states are pursuing the development of a new common and integrated gas market. One step towards integration is the realisation of the Trans-ASEAN Gas Pipeline (TAGP). This major project aims to interconnect existing and planned gas pipeline infrastructure within ASEAN. ASCOPE is mandated to implement the TAGP including through facilitating policy and regulatory frameworks. Virtual pipelines and a system based on LNG terminals are being considered as options that could enhance connectivity in addition to the original plan of building a physically integrated regional pipeline network.

ASCOPE's action plans include collaboration on pricing reform and environmental regulation. The initiative also aims to promote technology and knowledge transfer from mature markets to new markets in order to improve commercial and infrastructure readiness. ASCOPE also studies and promotes standardisation of commercial agreements (transaction size, LNG quality, etc.); and supports intra-ASEAN trades and open access for gas infrastructure.

A combination of solid local policies, investment by international players in the region and stability in global gas markets would enable gas to play a positive role in South-east Asia, which is a fast-growing region and an increasingly important catalyst of global energy market developments.

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