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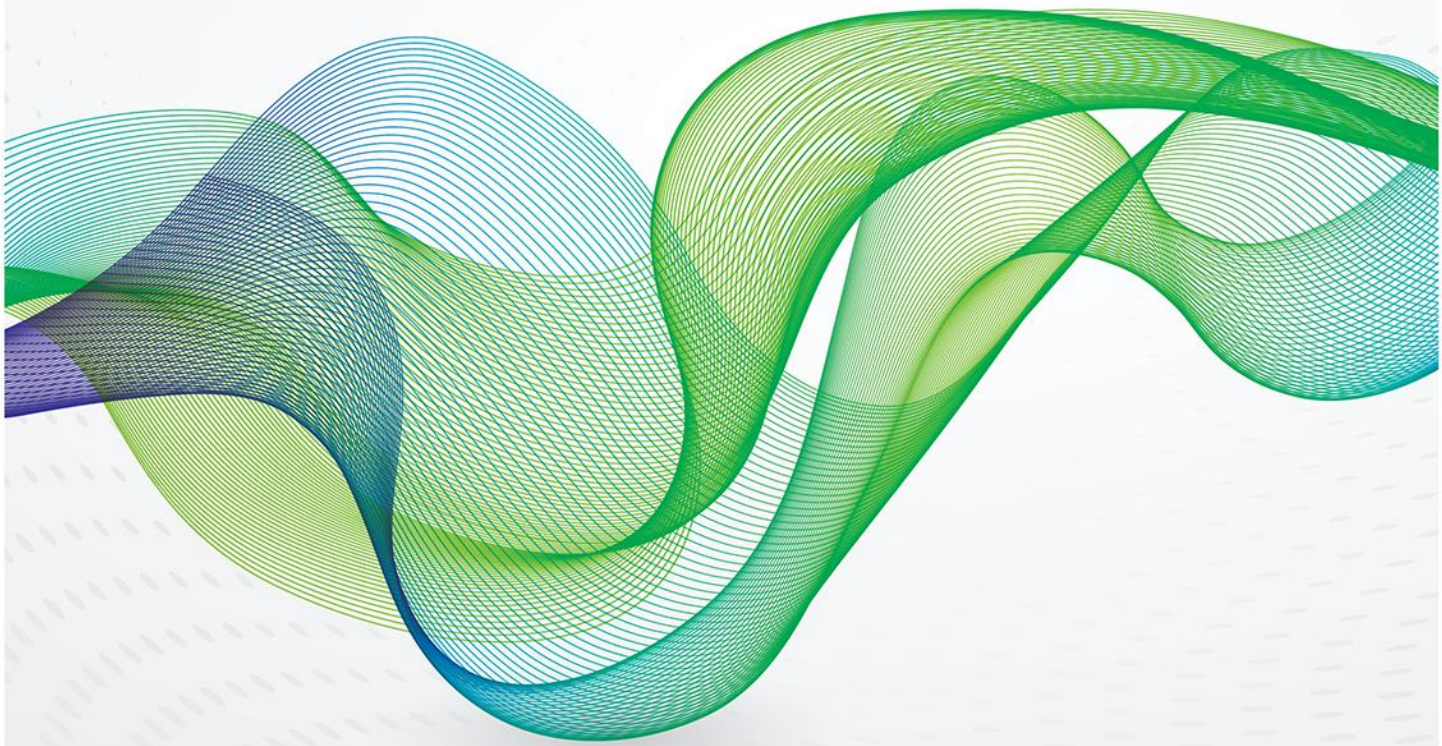
# Emerging Asia LNG demand



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## Preface

The growth in Asian gas demand is widely regarded as being one of the most crucial factors in the outlook for the global gas industry over the next two to three decades. With demand for methane in many other parts of the world being hampered by economic slowdown, undermined by a drive towards decarbonisation or amply supplied by indigenous production, the Asian market offers the main hope for the developers of new gas resources. Furthermore, Asia provides a huge opportunity for LNG suppliers in particular, because of the lack of pipeline infrastructure in the region.

Not surprisingly much of the analysis on Asia focuses on the largest markets, in particular the three foundation LNG importers (Japan, South Korea and Taiwan), the world's fastest growing gas market (China) and the market with the most potential for future growth due to the size of its population and relatively low gas demand to date (India). However, despite the obvious reasons for interest in these markets it would be wrong to ignore other smaller Asian countries which, when combined, also provide significant growth potential for gas. Indeed, as this report demonstrates, the opportunity in these smaller markets is actually as large as the combined growth forecast for China and India over the next two decades.

In addition, these smaller countries offer a diversity of analytical interest. Some have been gas exporters but declining supply and rising indigenous demand is turning them into importers and therefore important new markets for external gas supply. Others are examining their energy mixes in order to optimise security of supply risks, and improve their environmental performance, especially with regard to air quality. In both cases the opportunity for gas to displace coal, at least in part, provides demand upside potential. Meanwhile across the region the need for expanded gas infrastructure is being addressed in a multitude of ways, with a particular focus on LNG imports and the creation of key demand centres.

This paper examines all these issues and provides a detailed breakdown of the forecasts generated by our World Gas Model.[1] Of course, the output is only a snapshot at a point in time, as the key assumptions are constantly being adjusted, and we would encourage readers to contact us if they want to discuss updates or to examine any issues in more detail. Having said that, each section can offer some detailed insights into individual countries, while the final concluding section pulls together the emerging Asian LNG markets as a whole for those readers more focused on the aggregate picture. As such we hope that this document will provide a useful reference for analysts of the global gas and LNG markets.

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[1] The Natural Gas Programme at OIES uses the Nexant World Gas Model in all its analysis. For more details - https://www.nexanteca.com/program/world-gas-model

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Mike Fulwood and Martin Lambert
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## Executive Summary

This paper considers the potential for emerging markets in Asia to play a significant role in the future growth of LNG in the region. For many years, the 3 markets of Japan, South Korea and Taiwan were the key Asian markets (and to some extent the key LNG markets globally), with India and China joining from the early 2000s. In 2019, these 5 markets still accounted for 90 per cent of total Asian LNG imports.

Seven other Asian countries have begun importing LNG since the early 2010s – Thailand in 2011, Singapore and Malaysia in 2013, Pakistan and Indonesia[2] in 2014 and Bangladesh in 2018. Myanmar began on a small scale in the middle of 2020. Hong Kong, Vietnam and Philippines are constructing or planning to construct LNG import facilities in the near future. Sri Lanka and Cambodia have also been mentioned as possible importing countries.

Total LNG imports to the seven emerging Asian markets are projected to be around 44 bcm in 2020. In the base case forecast, total emerging Asian market LNG demand has the potential to grow to over 200 bcm by 2050. There is considerable uncertainty around gas demand forecasts, however, largely on account of economic uncertainties and competition from coal and renewables. Estimates of LNG demand range from 150 bcm in the low case to over 250 bcm in the high case. Thus, in aggregate, these emerging Asian markets could be as significant as the major growth markets of China and India.

The growth of domestic natural gas production was the primary driver of demand growth in many of the emerging markets. Indonesia and Malaysia also became major LNG exporters. Domestic production in many markets has stagnated or even (in Indonesia, Pakistan, Thailand and the Philippines) started to decline, driving the need for LNG imports.

The countries covered in this analysis of emerging Asian markets are faced with different issues. Some countries, such as Bangladesh and Pakistan have seen recent consumption growth, as LNG imports started up. A number of other countries have seen stagnant demand, in part limited by production and/or the ability to import. Gas is the dominant power generation fuel in some countries (Bangladesh, Singapore and Thailand). This appears unlikely to change in Singapore, but in Bangladesh and Thailand there could be some threat from coal. In other countries, coal is already a key fuel in power generation and with demand for electricity likely to grow significantly, the extent to which it will be supplied by coal or gas or renewables will be a key driver of gas demand.

For LNG imports to succeed, even where the supply-demand balance indicates a growing requirement, a key challenge remains the provision of infrastructure (e.g. regasification facilities and pipelines). In many countries, development of potential LNG imports has been delayed from initial expectation by government policy not providing an adequate framework to justify the required investment.

The sections below in this Executive Summary give a brief summary for each country, with further details in each chapter in the body of the report. Detailed charts of the base case projections and uncertainties for all of the emerging markets collectively are contained in the Summary and Conclusions Section at the end.

### *Indonesia*

Indonesian gas demand was 43.8 bcm in 2019. Of this, power generation was the largest source of gas consumption (36.4 per cent), followed by industry (35.8 per cent), energy sector own use (17.9 per cent), and non-energy use (9.6 per cent). There is negligible commercial or residential gas demand in Indonesia. The bulk of the growth in Indonesian power generation over the decade from 2008 to 2018 has been met by coal, perhaps not surprising given the abundant Indonesia coal reserves and increases in coal production.

Pipeline gas exports to Singapore and Malaysia peaked around 17.5 bcm in 2012 and are currently around 14-15 bcma. LNG exports peaked at 39 bcm in 1999, when Indonesia was the world's largest

[2] Indonesia trade has all been intra-country trade so far

LNG exporter, since when they have been declining to around 16.5bcm in 2019. As demand has grown in West Indonesia (Java, Sumatra and Bali) there has been a growth in internal Indonesian LNG movements with LNG supplies to these markets in the range 4-4.5 bcma between 2016 and 2019.

Indonesia gas production peaked in 2010, fell sharply in 2011/12 and has declined gradually thereafter. With several additional fields under development the long-term trend is for broadly stable production, with some increases in the early 2020s. Forecasts suggest that Indonesian gas demand is likely to grow faster than production over the coming two decades, with the result that Indonesia will eventually move from being a net gas exporter to being a net gas importer. This transition is likely to be gradual, with the 'tipping point' occurring around 2040, at which stage both LNG imports and LNG exports could be around 30 bcma, but with the imports all to the western islands and the exports from the eastern regions.

### *Philippines*

The only significant gas development in the Philippines is the Malampaya field which started production in 2001, ramped up to around 3 bcma by 2005 and has remained between 3 and 4 bcma since then. The field supplies gas via a 500km subsea pipeline to the city of Batangas, on the main island of Luzon about 100km south of the capital, Manila. More than 97 per cent of the gas production is consumed in the power sector, in plants with total capacity around 3,000MW all within 20km of the landfall in Batangas.

There appears to be little prospect of further significant gas discoveries and the Malampaya field is expected to decline from around 2022. The current production licence expires in 2024, but some production is expected to continue until around 2027 to 2029.

From as early as 2003 various project developers have proposed LNG import terminal projects in the Philippines. The Energy World Pagbilao project has been under construction for some time, but has been subject to rolling delays with little confidence it will actually be completed. Other projects have been trying to develop LNG imports to supply the existing gas fired power plants as Malampaya supply declines. Project development has been handicapped by difficulties in securing bankable power offtake commitments in the context of the deregulated power market and lack of a clear government policy or regulatory structure to create a business case for the required investments.

With competition in the power sector from coal and renewables, it is possible that LNG imports will not succeed in the Philippines. In a success case, at least one LNG import project would be completed, but even in this success case it is unlikely that LNG demand will be higher than around 7 bcma by 2040.

### *Hong Kong*

The gas industry has a long history in Hong Kong with distribution of manufactured gas starting in 1862, but most natural gas is used in power generation. Since 1996 gas consumed in power generation has been in the range 2.5 to 3.0 bcma with an additional 0.5 to 0.75 bcma used in the residential, commercial and industrial sectors. Gas supplies around 30 per cent of total power generation, with around 50 per cent from coal. Gas has been supplied since 1996 from the Yacheng field offshore Hainan Island in southern China. In 2012 the Hong Kong branch of China's West to East pipeline was completed, allowing additional gas supplies from Turkmenistan.

Under the government's Climate Action Plan, it is intended to increase the share of gas in power generation at the expense of coal. The Hong Kong Offshore LNG project is being developed by a consortium of CLP and Hong Kong Electric. The project has chartered the largest FSRU in the world, with a capacity of 263,000m$^3$. The precise status of the project is unclear, but it is believed that construction is now starting, with start of operations targeted for 2022.

In the most optimistic case gas consumption could grow from around 3 bcma today to around 10 bcma by 2050, but in a 2$^0$C scenario could grow to around 4 bcma by 2030 before falling to below 2 bcma by 2050. Pipeline imports are expected to grow from around 4 bcma up to around 5 bcma, and in a mid-case, LNG imports are expected to be around 2 bcma.

### *Bangladesh*

Natural gas use in Bangladesh started in 1959 and grew, based entirely on indigenous resources, to around 27 bcma by 2015. Indigenous production growth stalled after 2015, causing the government to restrict gas supply to businesses and households, giving priority to gas fired power plants. Natural gas dominates the power sector, with over 80 per cent share in 2016. In the industrial sector, including as a feedstock for fertiliser, gas has almost 50 per cent share. Gas is also used in the residential sector for cooking and water heating and for natural gas vehicles.

All current producing fields have reached their production plateaux, and domestic production is starting to decline. To meet growing demand for gas, LNG imports started in 2018, and a second terminal began operations in April 2019. Total import capacity currently is around 7.5 mtpa, and the government of Bangladesh is planning an onshore terminal which could handle a further 7.5 mtpa. There are plans for a number of other import terminals and the government intends to be able to import 35 mtpa by 2030.

There is a wide range of scenarios for future gas demand. Gas demand in 2018 was some 30 bcm and demand in 2040 could range from growing by fifty per cent to more than doubling. Domestic production in 2040 could be close to zero or similar to 2018 if "yet to find" reserves are developed. In our base case, LNG demand could grow to around 20 bcm by 2040, with our overall gas demand level projected at the lower end of the range.

### *Singapore*

Singapore began consuming natural gas in 1992 to displace oil in the power generation sector. Almost all power generation is gas-fired. Gas consumption in the industrial sector started in 2003. Singapore has no indigenous natural gas production. Until LNG imports began in 2013, all gas was imported by pipeline from Indonesia and Malaysia. Imports from Malaysia averaged around 1.5bcma while imports from Indonesia have been in the range 6 to 8 bcma over the last 10 years. LNG imports have grown gradually since 2013 to reach around 3 bcma.

The pipeline import contracts are expiring between now and 2023 and are unlikely to be renewed, certainly not at the current level. Total gas demand is expected to grow slightly from the current 13 bcm to a little over 14 bcma by 2040. Our expectation is that LNG will supply nearly all of this demand from 2023 onwards, with perhaps up to 1 bcma supplied by pipeline from Indonesia or from LNG imported by pipeline via Malaysia.

### *Thailand*

Thailand began consuming gas in 1981 in the power generation sector. Power generation accounts for around 30 bcma out of a total gas demand around 40 bcma. Gas was initially supplied from domestic production, mainly offshore in the Gulf of Thailand, with pipeline imports from Myanmar beginning in 1998 and plateauing around 10 bcma. As domestic production began to plateau and decline, Thailand began importing LNG in 2011, and currently imports around 5 bcma.

Gas is the dominant fuel in power generation with a share of around 70 per cent. Coal has around 20 per cent share. A little over 10 bcma of gas is used in the industrial sector and as a feedstock.

Thailand's first LNG regasification terminal at Map Ta Phut started operation in 2011 with a capacity of 5 mtpa. A second phase of 5mtpa was added in 2017, with potential for further expansion by a further 5mtpa. Plans are being developed for several other LNG import terminals, including by the power generator, EGAT.

There are a wide range of projections for future gas demand, mainly dependent on government policy regarding use of coal vs gas in power generation. The latest Power Development Plan envisages gas maintaining its share of a growing power generation market, while an earlier plan envisaged coal providing most new generation capacity. In our base case, total gas demand grows slightly to 2030 before declining gradually thereafter. Nevertheless, with declining domestic gas production and pipeline imports, LNG imports are envisaged to grow significantly to around 35 bcma by 2040.

### *Pakistan*

Natural gas accounts for around 25 per cent of Pakistan's primary energy supply, and would probably be higher were it not supply-constrained. Dwindling domestic gas supplies and delays in the implementation of LNG and pipeline import projects led to an increase in consumption of coal, which trebled (from 4 to 12 mtoe) between 2015 and 2019.

Total natural gas consumption has grown from around 5 bcma in the 1970s to around 45 bcma today. The power sector accounts for one third of the country's natural gas consumption. In contrast with other emerging markets, the residential and industry (including feedstock gas) sectors also play a very important role, with 21 per cent and 30 per cent shares of total gas demand respectively. The first LNG import project was commissioned in 2015, followed by a second in 2018. In 2019 Pakistan imported 11 bcm of LNG. There are potential plans to import gas by pipeline from Iran or from Turkmenistan via Afghanistan, but it is doubtful whether these plans will come to fruition.

Natural gas accounts for around 45 per cent of total power generation. Coal has jumped from less than 1 per cent in 2017 to 12 per cent with the start of two Chinese-backed coal-fired power plants with a total capacity around 2,500MW.

Optimistic forecasts of unconstrained demand growth suggest that gas demand could be 74.5 bcm in 2021 and 87 bcm by 2028. Owing to supply constraints, this is unlikely to be achieved. The discoveries in onshore Pakistan are not large and the offshore exploration efforts have not been successful. Although LNG is a possible alternative, it is unlikely that Pakistan will be importing volumes of 40-50 Bcma because the government might not be in a position to purchase or provide guarantees in hard currency for such volumes.

Unless there is a significant increase in domestic production, gas demand is likely to stay in the range 40-50 bcma until 2050, of which LNG supply could be around 30 bcma by 2035.

### *Malaysia*

Malaysia began consuming natural gas in the 1970s, but domestic demand did not grow strongly until the 1990s, and is currently around 40 bcma. Around half of domestic demand is for power generation. LNG exports from the single liquefaction complex at Bintulu in Sarawak started in 1983, and have been in the range 30-35 bcma since the late 2000s. The first floating LNG project with a capacity of 1.5 mtpa started operations offshore Sarawak in 2017. A second FLNG facility has been delayed but may commence operations in 2020.

Most domestic demand is in Peninsular Malaysia, whereas most production is in Sarawak and Sabah on the island of Borneo. Gas supply to the peninsula, includes piped gas from the Malaysia-Vietnam Commercial Arrangement Area (since 2003) and from the Malaysia-Thailand Joint Development Area (since 2005). To supplement pipeline supplies to the peninsula, Malaysia's first regasification terminal, with a capacity of 3.8 mtpa began operating near Malacca in 2013. A second import terminal with a capacity of 3.5 mtpa began operating near Johor in 2018. Several other regasification projects have been proposed in the last few years, but not come to fruition.

Production from the Malaysia-Thailand joint development area is expected to decline, as is production from other fields offshore Peninsular Malaysia. Production to feed the LNG plants in Sarawak is likely to be maintained around current levels. Domestic demand is unlikely to grow significantly, until 2030 at least, as most additional power generation is likely to be supplied by coal. Thereafter, some demand growth in the power sector is expected. With gradually declining domestic production, post 2030, LNG imports are likely to rise to between 20 to 25 bcma in the longer term.

### *Myanmar*

Myanmar oil and gas production has a very long history, starting with small onshore production in the 19$^{th}$ century. Significant gas production only started following the development of the offshore Yadana and Yetagun fields in the 1990s. Only around one-third of total gas production (around 6 bcma) is used domestically with the rest being exported to China (3 bcma) and Thailand (10 bcma). Over 60 per cent of domestic gas consumption is for power generation, and gas provides around one-third of total power generation.

Gas production from the existing fields is expected to decline significantly over the next 10 years, and a number of LNG import projects have been proposed since the early 2010s. These have made little progress, particularly on account of the inability to secure a bankable power purchase agreement for offtake of electricity.

A sudden acceleration in LNG development followed a series of major power cuts in May 2019, which led to the Ministry of Electricity and Energy announcing a tender in June 2019 for five emergency power projects totaling 1,040 MW, of which 3 plants in Yangon would use imported LNG. LNG supply involves use of a small shuttle tanker on account of the shallow draft in the river, and the first cargo arrived in June 2020. Now that LNG imports have started, and with government plans to increase electrification from the current 50 per cent to 100 per cent of households by 2030, our base case has LNG demand of 4 bcma by 2030 with potential upside to 6 bcma.

***Vietnam***

Significant gas production in Vietnam started in the mid-1990s and has plateaued around 10 bcma since the early 2010s. Most of the supply and demand is in the South East of the country as there is not yet an integrated pipeline infrastructure linking different regions. Gas and coal each have about 30 per cent share of power generation. Gas generation grew in the early 2000s based on indigenous sources of supply and the share of coal has grown more recently. Power generation accounts for around 80 per cent of total gas demand, with the balance for industrial use, including fertilizer production.

Government policy has ambitious climate targets, including expanding the share of renewables to 30 per cent of power generation by 2050. This green growth strategy may also benefit gas versus coal to some extent.

The Vietnamese authorities are already exploring the options for development of 7 LNG receiving terminals. The construction of the first terminal, Thi Vai, 70 km south of Ho Chi Minh City was started in October 2019 and is due onstream by 2022.

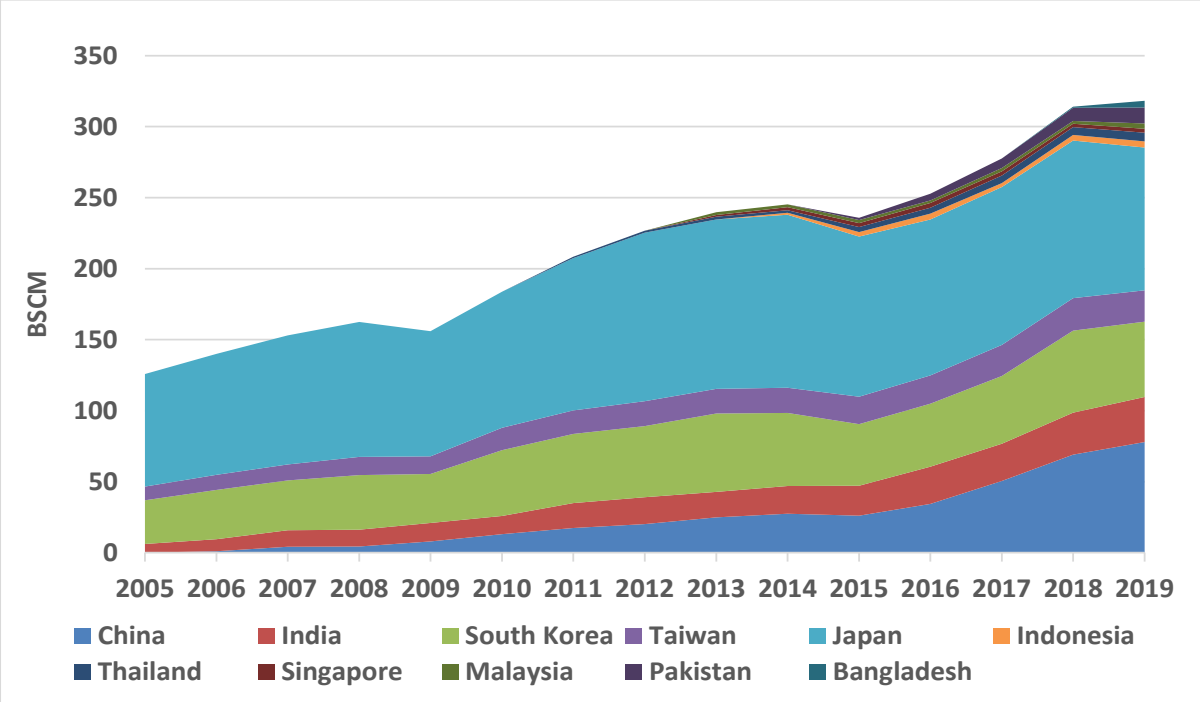
Future growth in domestic gas production is uncertain. An optimistic projection in the Gas Master Plan envisages growth from the current 10 bcma to 17-21 bcma by 2035, assuming development of a number of new fields, the most significant being Ca Voi Xanh and Block B. A more conservative forecast envisages growth to around 17 bcma by the late 2020s before declining towards 10 bcma by 2035. Demand growth will depend largely on the power sector, on fertiliser production and government policy. Total gas demand has the potential to rise to 31 bcma by 2035, but may only reach 23 bcma if supply constrained. In our base case, with declining domestic production from the late 2020s, there is potential for LNG imports around 10 bcma by 2035, which could rise further after that.

# INTRODUCTION AND BACKGROUND

## Background

A handful of import markets have, for a long time, been the main focus of the Asian LNG industry, with a few other countries playing a smaller and more variable role. The traditional importers were Japan, Korea and Taiwan, with India and China joining in the last 20 years. These "Big 5" importers still dominate the Asian markets, as shown in the figure below.

**Figure 1: Asian LNG Imports**




Source: IEA, Platts LNG Service

By 2019, the Big 5 accounted for some 90 per cent of total Asian LNG imports. Other Asian countries began importing in the early 2010's – Thailand in 2011, Singapore and Malaysia in 2013, Pakistan and Indonesia[3] in 2014 and Bangladesh in 2018. Myanmar began on a small scale in the middle of 2020. Hong Kong, Vietnam and Philippines are constructing or planning to construct LNG import facilities in the near future. Sri Lanka and Cambodia have also been mentioned as possible importing countries.

Import growth in the traditional markets of Japan, Korea and Taiwan has largely stalled, and there seems to be little prospect of any significant growth in aggregate for them. India and China, however, have a much brighter outlook and the new export projects which have recently come onstream, or will do in the next 5 years or so, have tended to focus their marketing on these two countries. The emerging Asian LNG markets in aggregate, however, could be just as important in terms of LNG import growth as China and India together,[4] although individually, they are likely to remain much smaller than any of the Big 5, apart from Taiwan.

[3] Indonesia trade has all been intra-country trade so far

[4] China and India together imported some 100 bcm of LNG in 2018 and by 2040 this could triple – a rise of 200 bcm – based on mid-2020 OIES projections

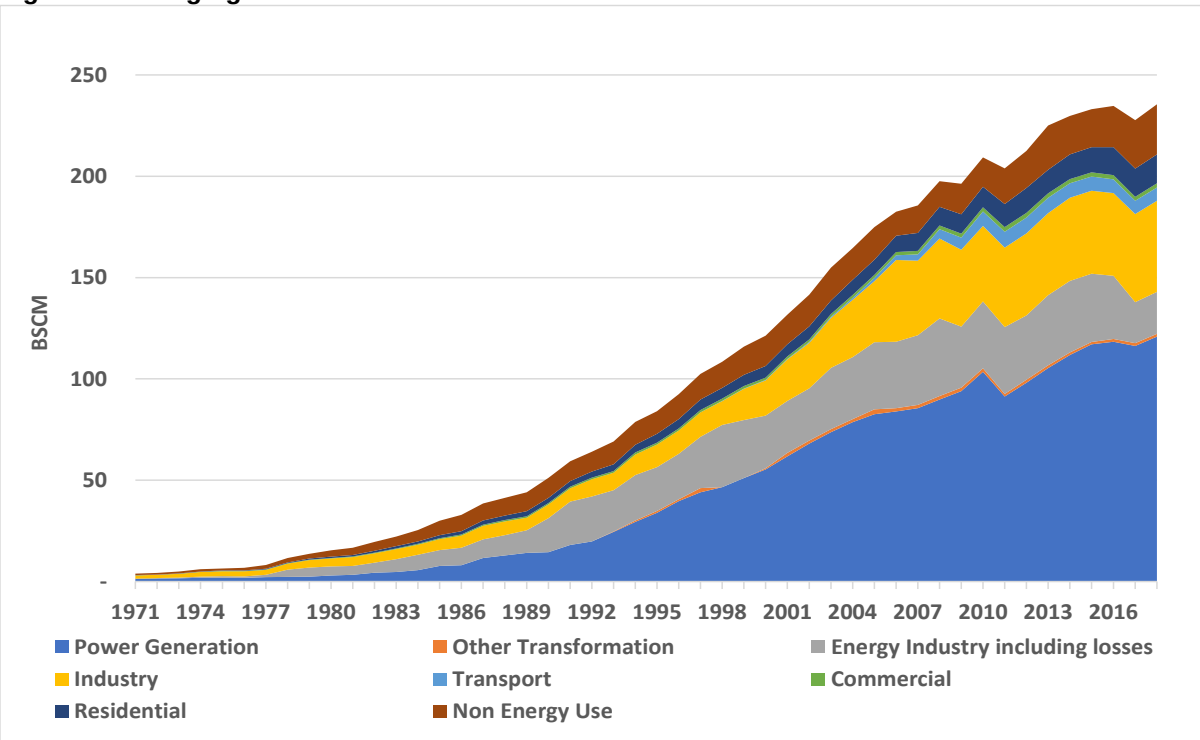
This paper focusses on the emerging markets and looks at their gas industry history, the infrastructure, government policy and regulation and projections of the supply – demand balance and the prospects for LNG imports. The future projections for each country are OIES estimates but published projections on gas supply and demand by companies, consultants, governments and international organisations have also been reviewed.

At the end, the projections for the emerging markets are aggregated to provide an assessment of the potential for LNG imports and the range of uncertainty.

## Gas Demand

Most gas demand in the 10 markets being considered has been supplied by domestic production or pipeline imports from neighbouring countries.

**Figure 2: Emerging Asian Markets Gas Demand**




Source: IEA

Gas in Power Generation has been a key driver of the growth in gas demand, together with Industry (including non-energy use[5]) and, in those countries with significant hydrocarbon production and export, use in the energy industry itself. The period of sustained growth was in the 1990s, but in the 2010s, gas demand growth has slowed significantly in aggregate. The table below shows 2018 gas demand by country and sector.

[5] Gas used as a feedstock – typically ammonia and methanol and other petrochemicals

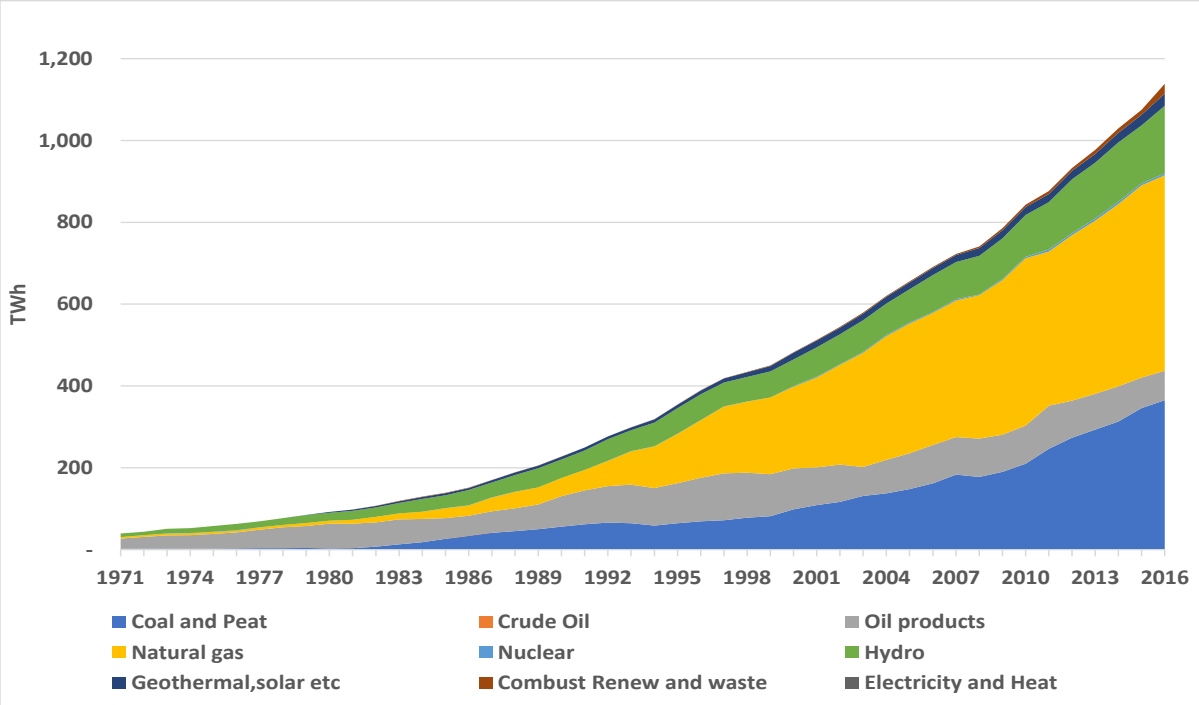
**Table 1: Emerging Asian Markets Gas Demand - 2018**

| BSCM | Power Generation | Other Transformation | Energy Industry including losses | Industry | Transport | Commercial | Residential | Non Energy Use | Total |
|---|---|---|---|---|---|---|---|---|---|
| Bangladesh | 16.6 | - | 0.6 | 4.8 | 1.4 | 0.3 | 4.5 | 1.4 | 29.5 |
| Hong Kong | 2.8 | - | - | 0.0 | - | 0.3 | 0.4 | - | 3.6 |
| Indonesia | 15.2 | - | 8.4 | 13.4 | 0.0 | 0.2 | 0.0 | 3.8 | 41.0 |
| Malaysia | 16.1 | 1.5 | 1.6 | 8.5 | 0.2 | 0.0 | 0.0 | 12.2 | 40.1 |
| Myanmar | 3.5 | - | 0.6 | 0.3 | 0.2 | 0.0 | - | 0.2 | 4.7 |
| Pakistan | 15.1 | - | 1.8 | 10.7 | 2.3 | 1.0 | 9.3 | 4.9 | 45.2 |
| Philippines | 3.9 | - | 0.1 | 0.1 | - | - | - | - | 4.1 |
| Singapore | 11.4 | - 0.0 | 0.0 | 1.7 | 0.0 | 0.1 | 0.1 | - | 13.3 |
| Thailand | 28.0 | - | 7.5 | 4.2 | 2.5 | 0.0 | - | 2.2 | 44.5 |
| Vietnam | 8.3 | - 0.0 | - | 1.3 | 0.0 | - | - | - | 9.6 |
| Total | 120.8 | 1.5 | 20.7 | 45.0 | 6.6 | 2.0 | 14.3 | 24.8 | 235.6 |

Source: IEA

Pakistan and Bangladesh consume significant volumes of gas in the residential sector and also use gas in transport in NGVs, as does Thailand. Malaysia consumes over 25 per cent of its gas as a feedstock.

**Figure 3: Emerging Asian Markets - Power by Fuel**




Source: IEA

In the power sector, natural gas began to displace oil products in the 1980s in many countries and, with the addition of coal and hydro in some countries, this led to a rapid rise in power generation.

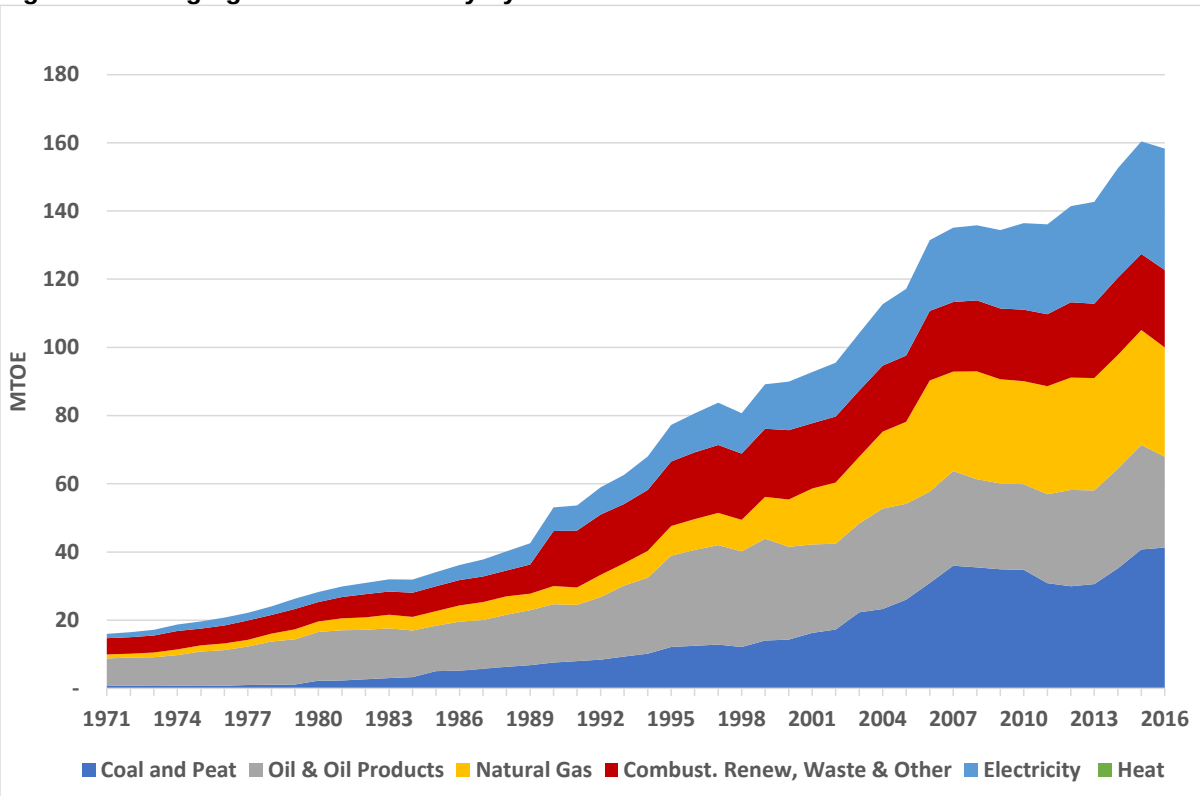
**Table 2: Emerging Markets - Power by Fuel 2016**

| TWH | Coal and Peat | Crude Oil | Oil products | Natural gas | Nuclear | Hydro | Geothermal ,solar etc | Combust Renew and waste | Total |
|---|---|---|---|---|---|---|---|---|---|
| Bangladesh | 1.1 | - | 9.7 | 52.8 | - | 0.6 | 0.2 | - | 64.3 |
| Hong Kong | 24.8 | - | 0.4 | 13.0 | - | - | 0.0 | 0.1 | 38.3 |
| Indonesia | 135.4 | - | 15.7 | 65.7 | - | 19.4 | 10.7 | 1.8 | 248.6 |
| Malaysia | 69.2 | - | 1.2 | 65.2 | - | 20.0 | 0.3 | 0.8 | 156.7 |
| Myanmar | 0.0 | - | 0.1 | 8.1 | - | 9.7 | - | - | 17.9 |
| Pakistan | 0.2 | - | 37.4 | 33.3 | 4.9 | 36.6 | 1.1 | 0.6 | 114.0 |
| Philippines | 43.3 | - | 5.7 | 19.9 | - | 8.1 | 13.1 | 0.7 | 90.8 |
| Singapore | 0.6 | - | 0.4 | 49.1 | - | - | 0.1 | 1.4 | 51.7 |
| Thailand | 35.8 | - | 0.3 | 120.3 | - | 4.8 | 5.6 | 10.2 | 177.0 |
| Vietnam | 53.7 | - | 1.1 | 45.6 | - | 64.1 | 0.2 | 0.1 | 164.8 |
| Total | 364.0 | - | 71.8 | 473.0 | 4.9 | 163.4 | 31.3 | 15.6 | 1,124.0 |

Source: IEA

Natural gas is a dominant fuel in power generation in Bangladesh, Singapore and Thailand. It is on a par with coal in Malaysia and Vietnam. Coal is the largest fuel in Hong Kong, Indonesia and Philippines, but natural gas also has significant shares. While oil products have declined in importance, there is still significant use in Bangladesh, Indonesia, Pakistan and Philippines, where natural gas and coal could increase their market share. Natural gas continues to face strong price competition from coal for power generation in many emerging markets. As renewable costs continue to fall, they provide a further threat to gas-fired generation although renewables penetration is still small in most markets.

**Figure 4: Emerging Markets - Industry by Fuel**




Source: IEA

Similar to the power sector, in Industry there has been a move away from oil products towards all fuels, including natural gas and coal, as well as combustible renewables (biofuels) and electricity.

**Table 3: Emerging Markets - Industry by Fuel 2016**

| | Coal and Peat | Oil & Oil Products | Natural Gas | Combust. Renew | Electricity | Total |
|---|---|---|---|---|---|---|
| Bangladesh | 1.4 | 0.3 | 3.7 | - | 2.5 | 7.9 |
| Hong Kong | 1.3 | 0.7 | 0.0 | - | 0.3 | 2.3 |
| Indonesia | 9.5 | 7.5 | 9.8 | 6.2 | 5.9 | 38.8 |
| Malaysia | 1.8 | 2.7 | 6.0 | - | 5.8 | 16.3 |
| Myanmar | 0.3 | 0.7 | 0.3 | 0.3 | 0.2 | 1.8 |
| Pakistan | 5.1 | 2.1 | 6.2 | 3.6 | 2.3 | 19.4 |
| Philippines | 2.8 | 1.5 | 0.1 | 1.2 | 2.1 | 7.6 |
| Singapore | 0.2 | 3.4 | 1.0 | - | 1.6 | 6.2 |
| Thailand | 6.1 | 5.7 | 3.3 | 8.6 | 7.6 | 31.4 |
| Vietnam | 12.9 | 2.0 | 1.6 | 2.8 | 7.3 | 26.6 |
| Total | 41.3 | 26.6 | 32.0 | 22.7 | 35.6 | 158.3 |

Source: IEA

Natural gas has significant shares in Industry in Bangladesh, Indonesia, Malaysia, Pakistan and Thailand. These are all countries where the natural gas industry grew on the back of indigenous production. Coal is also used extensively in Hong Kong, Indonesia, Pakistan, Philippines, Thailand and Vietnam. There is scope in almost all countries for natural gas and coal to gain market share at the expense of oil and oil products. The category called Combustible Renewables is not generally the use of green biofuels, but more likely the burning of wood and in some cases crops in more remote areas. As these economies grow, the use of wood and other combustibles is likely to be phased out.

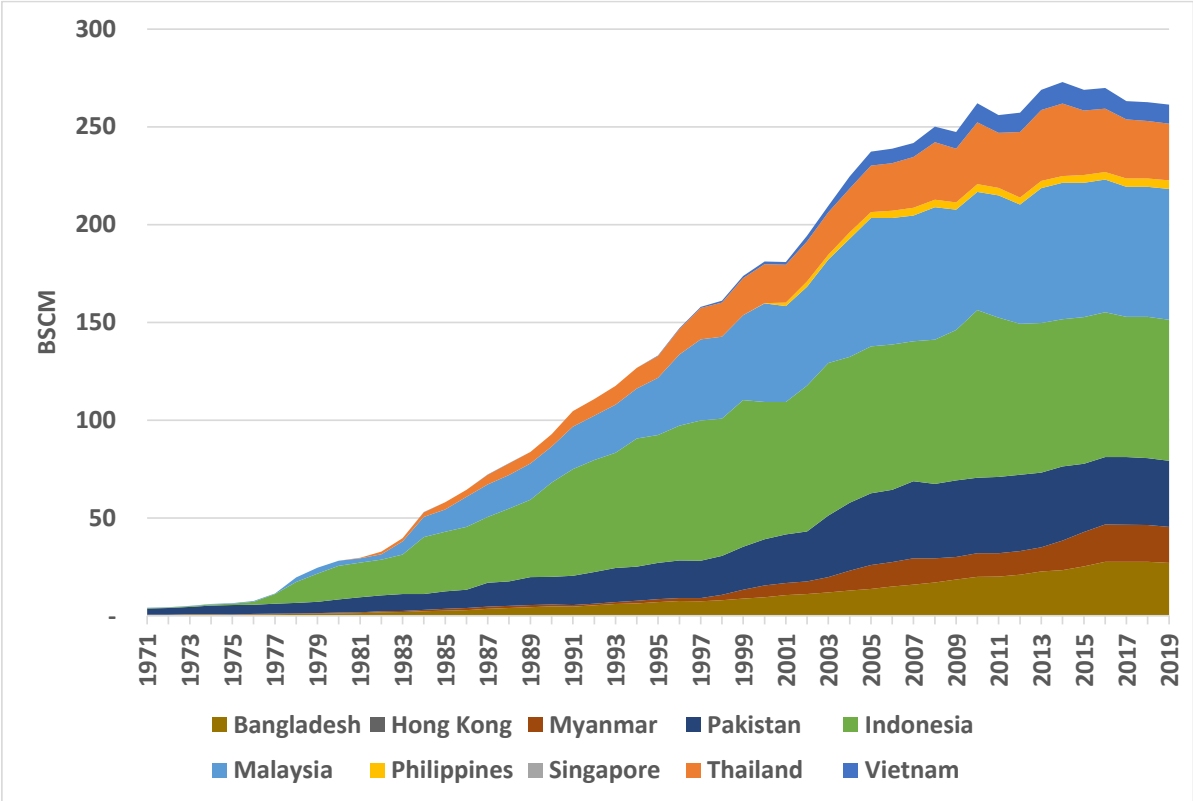
## Supply – Demand Balance

The growth of domestic natural gas production was the primary driver of demand growth in many of the emerging markets. The largest producers are Indonesia and Malaysia, who are also major exporters. In the 2010s, production growth stalled overall and even began to decline in Pakistan, Indonesia and Thailand.

The growth of production in the 1980s supported both domestic demand growth and LNG exports from Indonesia and Malaysia. Pipeline trade in the region began in the late 1990s, with exports from Malaysia to Singapore followed by Indonesia to Singapore in the early 2000s and also Indonesia to Malaysia. Hong Kong began imports from China in 1995 and Thailand from Myanmar in 1998. The only pipeline trade outside the ASEAN countries is from Myanmar to China which began in 2014.

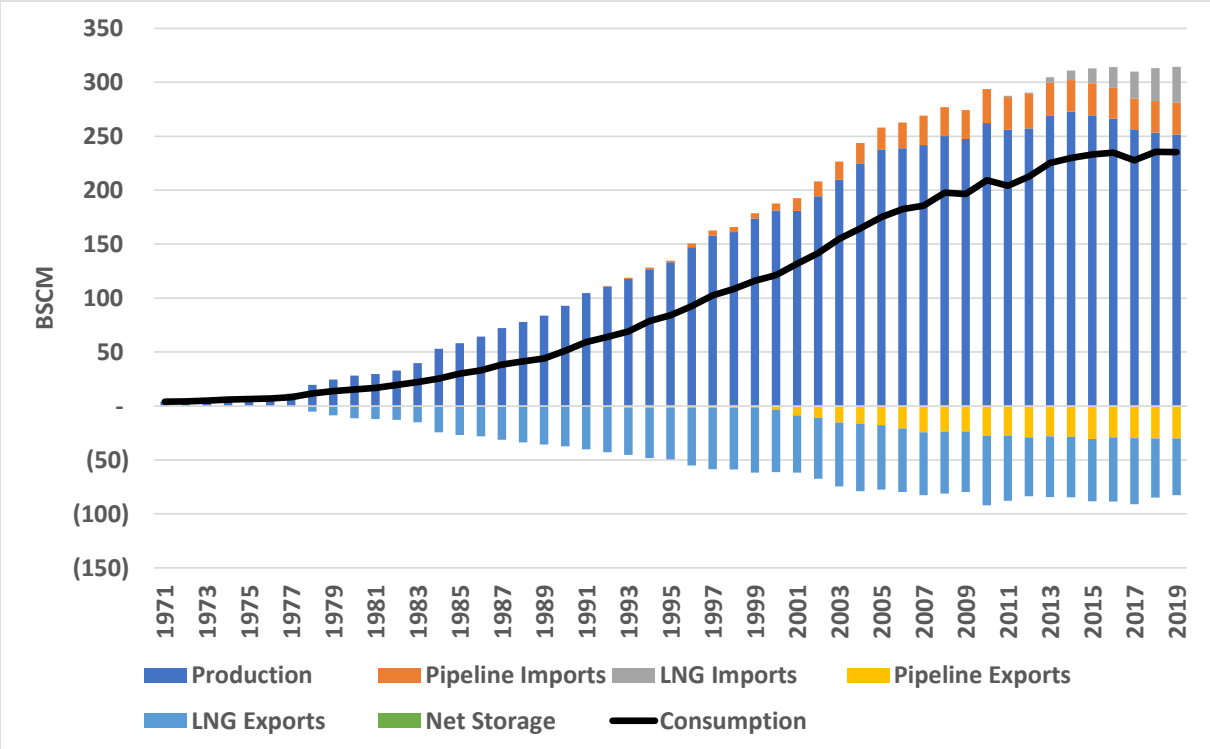
As noted above, LNG imports in emerging Asian markets began in the early 2010s, as production growth stalled and began to decline in some countries. Consumption growth also began to slow, but with total LNG production being broadly maintained, the region's net exports (shown in Figure 7 as negative net imports) have declined from 60 bcma in the 2000s to 20 bcm in 2019.

**Figure 5: Emerging Markets – Production**



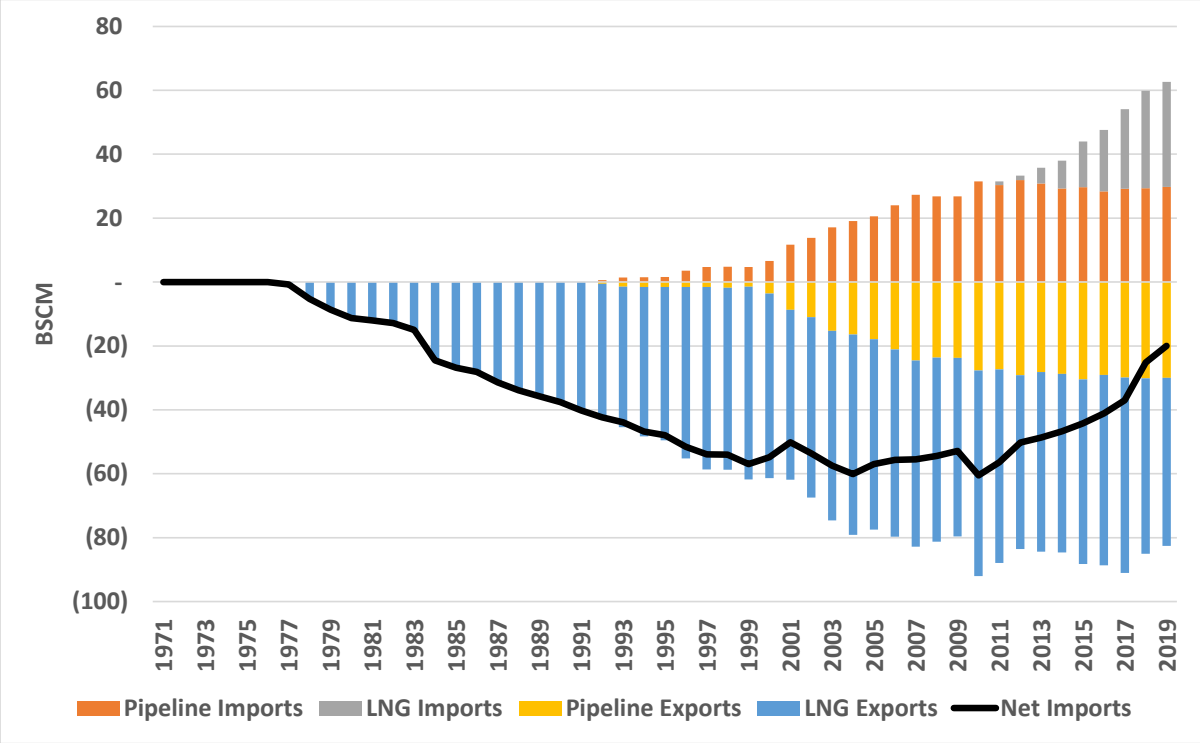

Source: IEA

**Figure 6: Emerging Asian Markets - Supply - Demand Balance**




Source: IEA

**Figure 7: Emerging Asian Markets - Net Imports**




Source: IEA

## Key Issues

The countries covered in this analysis of emerging Asian markets are faced with different issues. The dominant use of gas is in Power, followed by Industry (including energy industry use and non-energy use). One common theme for those countries with indigenous production is either significantly declining production or, at best, stagnating production. A key question, therefore, is what are the prospects for the development of more reserves and for production declines to be reversed.

Some countries, such as Bangladesh and Pakistan have seen recent consumption growth, as LNG imports started up. A number of other countries have seen stagnant demand, in part limited by production and/or the ability to import.

On the demand side, a key issue for gas demand is competition with coal and renewables in the power market and in some cases in the industry sector. It was noted above that gas is dominant in some countries (Bangladesh, Singapore and Thailand). This appears unlikely to change in Singapore, but in Bangladesh and Thailand there could be some threat from coal. In other countries, coal is already a key fuel in power generation and with demand for electricity likely to grow significantly, how much of this will be supplied by coal or gas or renewables will be a key driver of gas demand.

The decline of the use of crude oil and oil products in both the power sector and industry has been a continuing trend, with natural gas often benefitting. There is less scope in power now for this to happen in the future, although there is some scope in Bangladesh, Indonesia and Pakistan. In industry, however, there remains significant scope for replacement of oil. However, coal and renewables could take up some of this displacement in power and coal and electricity in industry.

In respect of LNG imports, even if a growing requirement is suggested by the supply-demand balances in each country, the provision of infrastructure (regasification facilities, port infrastructure), access and pipeline offtakes will be key. In many countries, development of potential LNG imports has been delayed from initial expectations by government policy not providing an adequate framework to justify the required investment.

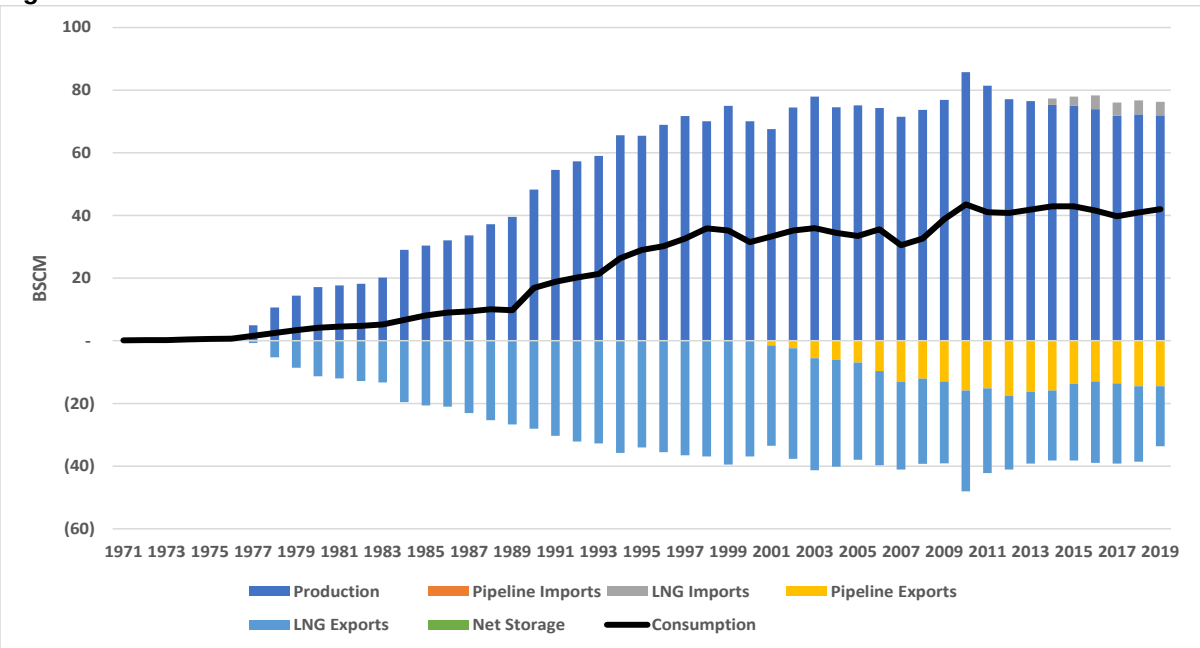
# INDONESIA

## Historic Supply-Demand

### Gas Balance

Gas production in Indonesia grew from less than 1 billion cubic metres (bcm) in 1975 to 75 bcm in 1999. Production then peaked at 86 bcm in 2010, before declining gradually to 67.5 bcm in 2019. In parallel, Indonesian gas consumption grew from less than 1 bcm in 1976 to 10 bcm in 1988, 35 bcm in 1998, and reached the current level of around 40-45 bcma in 2009. According to the IEA, Indonesia had 2.8 trillion cubic metres of proven gas reserves at the end of 2017, with a reserves-to-production ratio of 38 years. BP suggests a similar figure for 2018, but revised this down to 1.4 tcm for 2019, with the R/P ratio falling to 21 years.[6] [7]

**Figure 8: Indonesian Gas Balance**




Source: Data from the IEA; Graph by the author[8]

For comparison with the IEA data, the latest data from the Indonesian Ministry of Energy and Mineral Resources offers the following breakdown of Indonesia's gas balance in 2018:

[6] BP, 2020. *Statistical Review of World Energy*. p.32, 34, and 36
[7] IEA, 2020. *Natural Gas Information 2019*. p.II.59.
[8] 'Net LNG Imports' (in this case negative) refers only to LNG delivered to non-Indonesian destinations

**Table 4: Indonesian Gas Balance (2018)**

| | Natural Gas (NG) | | LNG | |
|---|---|---|---|---|
| | Thousand boe | bcm of NG | Thousand boe | bcm of NG equivalent |
| **Primary Energy Supply** | **413,373** | **65.17** | **-125,063** | **-19.72** |
| *Production* | *460,281* | *72.57* | *0* | *0.00* |
| *Exports* | *-46,908* | *-7.40* | *-125,063* | *-19.72* |
| **Transformation** | **-279,979** | **-44.14** | **153,612** | **24.22** |
| *Refinery* | *-3,801* | *-0.60* | *0* | *0.00* |
| *Processing (to LNG)* | *-179,391* | *-28.28* | *180,174* | *28.41* |
| *LNG regasification* | *0* | *0.00* | *-25,666* | *-4.05* |
| *Power plant* | *-96,788* | *-15.26* | *-896* | *-0.14* |
| **Own use & losses** | **-43,737** | **-6.90** | **-28,549** | **-4.50** |
| *During transformation* | *-3,801* | *-0.60* | *0* | *0.00* |
| *Energy use / Own use* | *-39,937* | *-6.30* | *0* | *0.00* |
| *Transmission & distribution* | *0* | *0.00* | *-28,549* | *-4.50* |
| **Final Energy Supply** | **-89,657** | **-14.14** | **0** | **0.00** |
| Statistical Discrepancy | 5,989 | 0.94 | 0 | 0.00 |
| **Final Consumption** | **-95,646** | **-15.08** | **0** | **0.00** |
| *Industry* | *-95,177* | *-15.01* | *0* | *0.00* |
| *Transportation* | *-234* | *-0.04* | *0* | *0.00* |
| *Household* | *-203* | *-0.03* | *0* | *0.00* |
| *Commercial* | *-32* | *-0.01* | *0* | *0.00* |
| *Other* | *0* | *0.00* | *0* | *0.00* |
| **Non-Energy Use** | **-25,568** | **-4.03** | **0** | **0.00** |
| Balance (excluding non-energy use) | 0 | 0 | 0 | 0 |

Source: Data from Indonesian Energy Ministry; Table by the author[9] [10]

## Gas Consumption by Sector

The BP Statistical Review of World Energy states Indonesian gas demand to be 43.8 bcm in 2019, down slightly (-1.6 per cent) from 44.5 bcm in 2018. Although a detailed breakdown of demand by sector is possible only with data from the IEA and Indonesian Energy Ministry, which extends only to 2018, the small size of the shift in demand between 2018 and 2019 means that the trends in sectoral demand identified are likely to have continued. According to IEA/Indonesian Energy Ministry data, in 2018, total domestic gas demand in Indonesia was 41.87 bcm. Of this, power generation was the largest source of gas consumption (36.4 per cent), followed by industry (35.8 per cent), energy sector own use (17.9 per cent), and non-energy use (9.6 per cent). Together, these sectors accounted for 99.8 per cent of Indonesian gas consumption, thus highlighting the almost complete lack of gas consumption in the commercial and residential sectors.

In the decade between 2008 and 2018, Indonesian power generation rose by 79 per cent, from 149 TWh to 267 TWh. Where IEA data is unavailable, data from the Indonesian Ministry for Energy and Mineral Resources *Handbook of Energy & Economic Statistics* has been used.

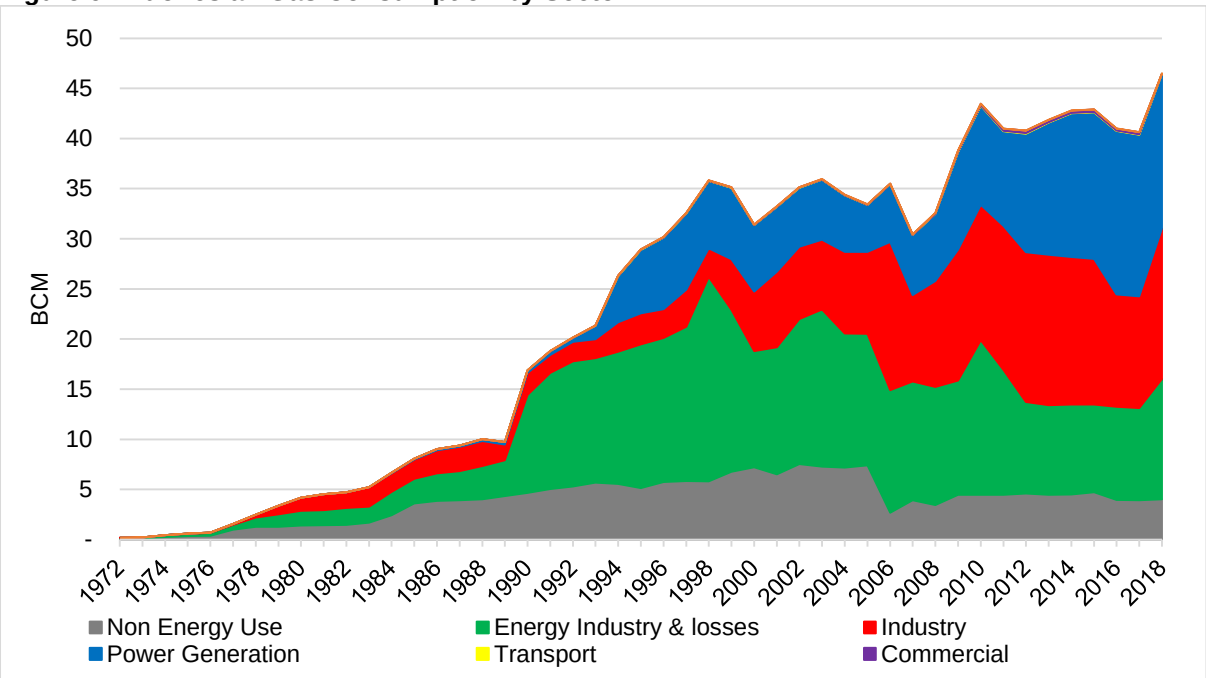
The two sources agree that during this period, the share of coal in power generation rose from 41 per cent to 54-55 per cent, while the share of oil products fell from 29 per cent (IEA) or 14 per cent (Energy Ministry) to 6-8 per cent. The shares of hydro (8 per cent) and the combined share of geothermal, wind,

[9] Ministry of Energy & Mineral Resources of the Republic of Indonesia, 2019. *Handbook of Energy & Economic Statistics of Indonesia (January 2019)*. https://www.esdm.go.id/assets/media/content/content-handbook-of-energy-and-economic-statistics-of-indonesia-2018-final-edition.pdf. p.16-17

[10] The original data in thousand barrels of oil equivalent (boe) has been converted into bcm using the conversion factor given in the Handbook (1 million standard cubic feet = 0.1796 boe), and subsequent conversion from cubic feet to cubic metres.

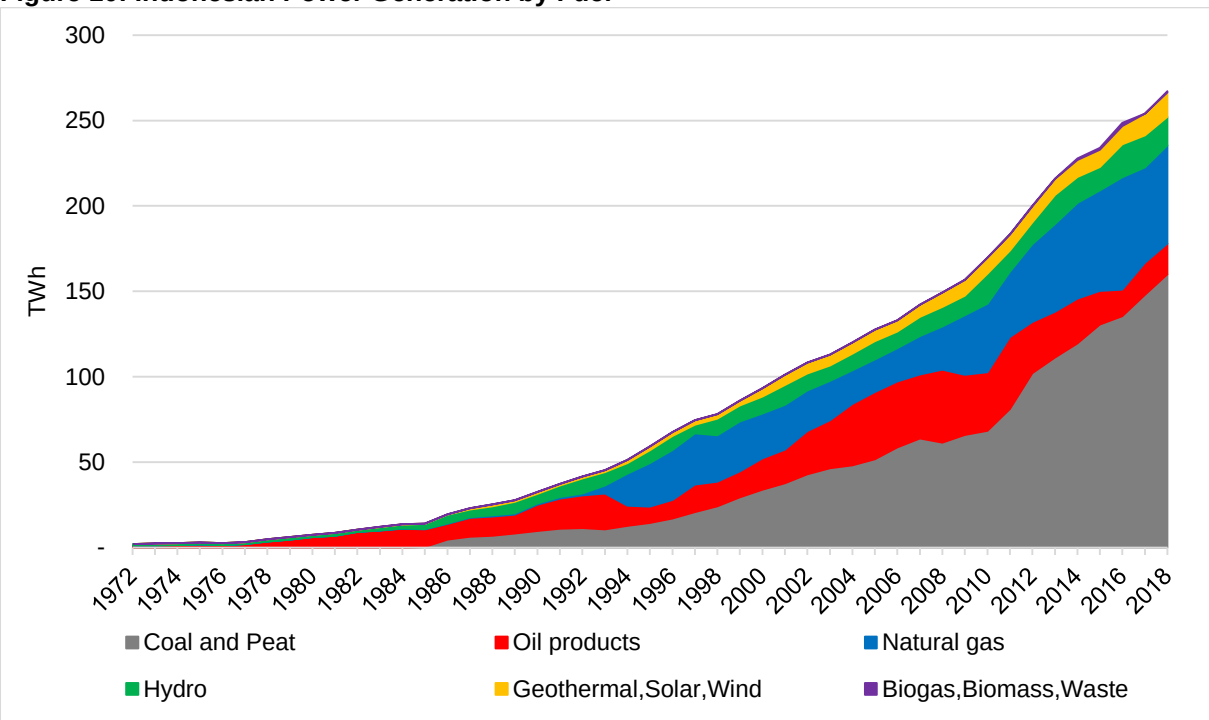
and solar (4-6 per cent) remained virtually unchanged, while the combined share of biomass, biogas, and waste remained below 1 per cent. [11]

**Figure 9: Indonesian Gas Consumption by Sector**




Source: Data from the IEA (up to 2016) and Indonesian Energy Ministry (2018); Graph by the author

**Figure 10: Indonesian Power Generation by Fuel**




Source: Data from the IEA; Graph by the author

[11] Ministry of Energy, 2019. *Handbook*. p.90-93

The sources diverge on the share of gas in power generation in 2008. The IEA states 17 per cent while the Indonesian Ministry states 32 per cent. The difference is accounted for by differing reported shares of oil products in power generation. However, the two sources agree that the share of gas in power generation in 2016 was 25-26 per cent, when total power generation was 248-249 TWh.

During this period, the IEA data suggests that gas demand for power generation more than doubled, from around 6.5 bcm in 2008 to around 16 bcm in 2016, as gas-fired power generation rose to 62-66 TWh in 2016. Statistics from the Indonesian Energy Ministry suggest a more modest increase, from 6.3 bcm in 2008 to 9.5 bcm in 2016.[12] Unfortunately, the data for 2018 in different sections of the *Handbook* diverge. The table for Natural Gas and LNG Supply and Demand suggests gas consumption for power generation of 263,534 million cubic feet (7.5 bcm), while the Energy Balance for 2018 table states gas consumption in power plants as 96.788 million barrels of oil equivalent (15.26 bcm).[13]

It is clear that the bulk of the growth in Indonesian power generation over the decade from 2008 to 2018 has been met by coal. Coal-fired power generation grew from 61 TWh in 2008 to 160 TWh in 2018, while gas-fired power generation grew from 47 TWh to 57 TWh, hydro grew from 12 TWh to 17 TWh and renewables (geothermal, wind, and solar) grew from 8 TWh to 14 TWh. By contrast, oil-fired power generation fell slightly from 21 TWh to 18 TWh, and power generation from combustion of biomass, biogas, and waste remained below 1 TWh.

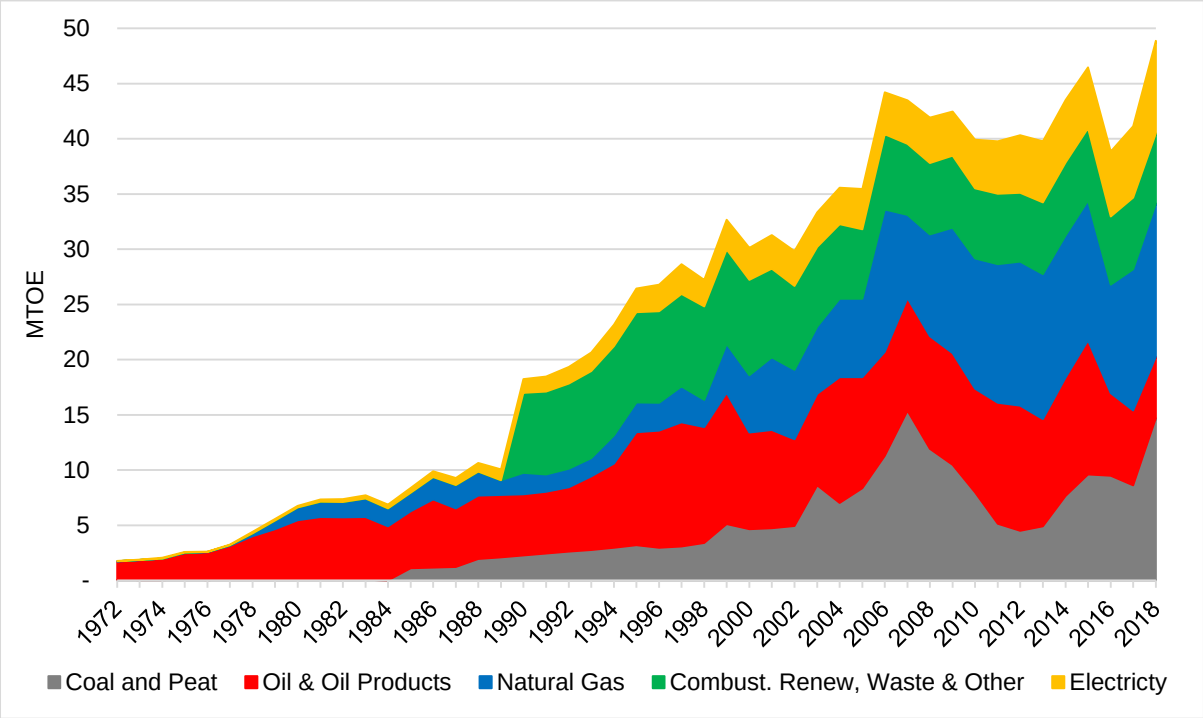
If these trends continue, coal is likely to continue playing the primary role in Indonesian power generation. This is unsurprising, given that Indonesian steam coal production more than doubled between 2008 and 2018, from 240 million tonnes to 558m tonnes. Even a doubling of domestic coal sales, from 53m tonnes to 115m tonnes – within which coal deliveries to power plants tripled from 31m tonnes to 91m tonnes – failed to dent the growth in exports from 191m tonnes to 356m tonnes.[14] This growth in coal production and consumption for power generation – in contrast to the current slow decline in gas production and subdued growth in gas consumption for power generation – should be remembered in the later discussion of forecasts for future gas demand in power generation.

[12] Ministry of Energy, 2019. *Handbook*. p.84

[13] Ministry of Energy, 2019. *Handbook*. p.16-17, 84-85

[14] Ministry of Energy, 2019. *Handbook*. p.63-66

**Figure 11: Indonesian Industrial Energy Consumption by Fuel**




Source: Data from the IEA (up to 2016) and Indonesian Energy Ministry (2017-18); Graph by the author

Between 2008 and 2018, Indonesian industrial energy consumption remained relatively stable at around 39-43 mtoe per year, with peaks in 2015 (46.5 mtoe) and 2018 (48.9 mtoe). The share of gas in industrial energy consumption in that period is open to debate: The IEA data (2008-2016) shows the share of gas rising from 22 per cent to 32 per cent in 2011, before falling back to 25 per cent in 2016. Data from the Indonesian Energy Ministry shows the share of gas in 2008 and 2018 as being 28 per cent, rising to a peak of 33-34 per cent in 2013-14, before falling back again. While the shares of biomass (13-14 per cent) and coal (29-30 per cent) are unchanged between 2008 and 2018, albeit with fluctuations in between, the notable shifts are the declining share of oil and oil products (including LPG) from 19 per cent to 11 per cent, and the rise in the share of electricity, from 9 per cent to 17 per cent. In this sector, total energy consumption rose slightly from 46.8 mtoe to 48.9 mtoe – a rise of 4.5 per cent.[15] Specifically, natural gas demand over the past decade has remained stable. The Indonesian Ministry of Energy report demand of 15.2-16.2 bcma, except for a drop to 12.9 bcm in 2012, while the IEA report stable demand of 12-13 bcma, with a drop to 10 bcm in 2016.[16]

While the share of gas in household/residential energy demand has remained below 0.2 per cent, the past decade has seen a shift in the shares of competing fuels. The share of kerosene fell from 47.5 per cent to 2.4 per cent, while the share of LPG rose from 16 per cent to 48.2 per cent, and the share of electricity rose from 36.4 per cent to 49.1 per cent. In this sector, total energy consumption remained stable, falling slightly from 22.4 mtoe to 22.1 mtoe – a fall of 1.3 per cent.[17]

It is a similar story in the Indonesian commercial sector in the decade between 2008 and 2018. The shares of gas (around 1 per cent) and LPG (around 4 per cent) have remained stable, while the shares of kerosene (8 per cent down to 0.4 per cent) and gasoil (16 per cent down to 8 per cent) have been

[15] Ministry of Energy, 2019. *Handbook*. p.42-45
[16] Ministry of Energy, 2019. *Handbook*. p.42-45
[17] Ministry of Energy, 2019. *Handbook*. p.47-48

taken by the rising share of electricity (70 per cent to 87 per cent). In this sector, total energy consumption rose from 4.1 mtoe to 6.3 mtoe – a rise of 54 per cent.[18]

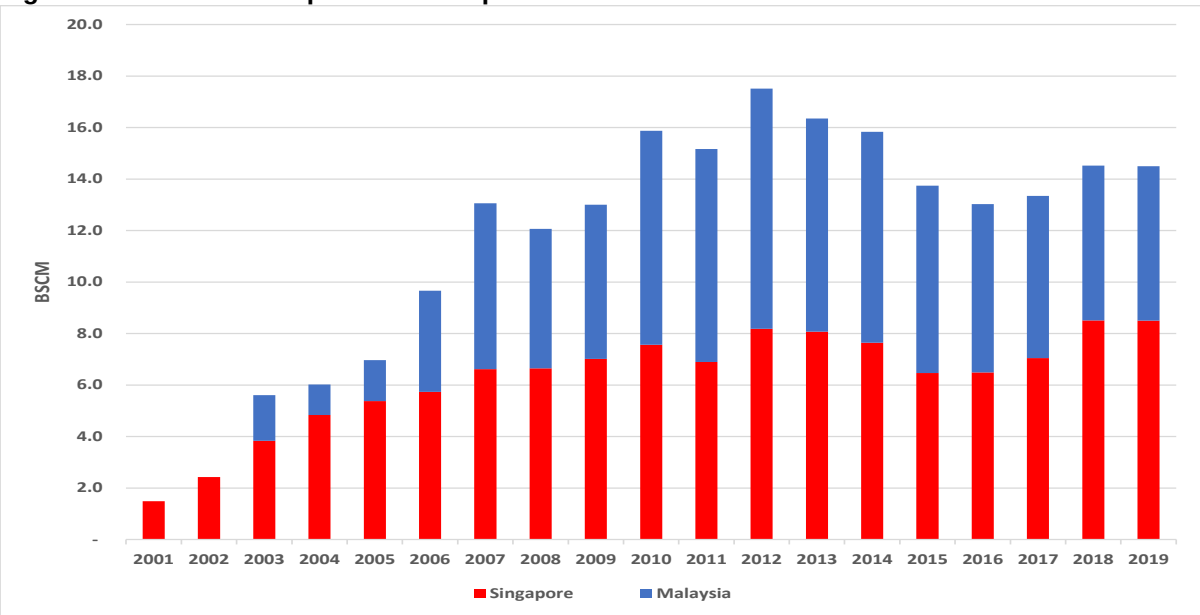
In the transportation sector, the shares of gas and electricity each remain below 0.1 per cent. In the decade from 2008 to 2018, the share of gasoline fell from 61.5 per cent to 50.8 per cent and the share of gasoil fell from 26.5 per cent to 9.9 per cent. These shares were taken by the rising share of bio gasoil, which rose from 3.3 per cent to 29.1 per cent. In this sector, total energy consumption rose from 27.1 mtoe to 57.2 mtoe – a rise of 111 per cent.[19]

Overall, Indonesian gas demand in 2018 was 42 bcm, and has been relatively stable at around 39-43 bcma since 2009. While gas demand for power generation has risen steadily over the past decade, final gas consumption in the industrial, commercial, residential, transport, and non-energy sectors has remained relatively stable.

## Pipeline and LNG Exports

Pipeline gas exports have been significant. As Figure 12 illustrates, combined pipeline exports to Singapore and Malaysia grew to a peak of 17.5 bcm in 2012, before declining to 13-14 bcm per year (bcma) in 2015.

**Figure 12: Indonesian Pipeline Gas Exports**




Source: Data from the IEA (up to 2017) and BP (2018, 2019); Graph by the author [20]

However, despite the existence of pipeline exports, it is as an LNG exporter that Indonesia made its name. Exports grew from less than 1 bcm in 1977 to 13 bcm in 1983. Total LNG exports peaked at 39 bcm in 1999, and have been 20-22 bcma since 2014, reaching approximately 20 bcm in 2018 before falling substantially to 16.5 bcm in 2019.

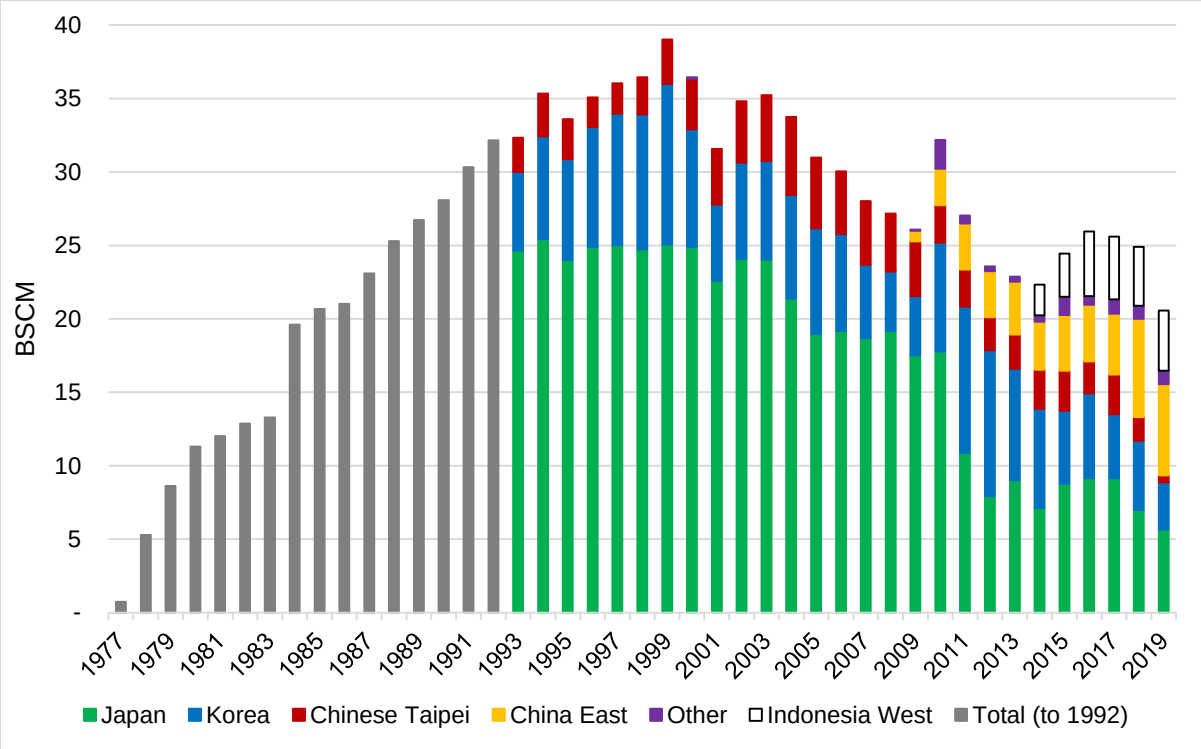
Until 2008, the only export destinations for Indonesian LNG were Japan, South Korea, and Chinese Taipei (Taiwan). Exports to Japan reached a high plateau of 24-25 bcma from 1993 to 2003, before declining to the level of 7-9 bcma from 2012 to 2018, finally falling to 5.7 bcma in 2019. Exports to South Korea peaked at 11 bcma in 1999, before falling and recovering to a 'second peak' of 10 bcma in 2011 and 2012, falling to a level of 4-6 bcma from 2015 to 2018, and finally dropping to 3.2 bcma in 2019.

[18] Ministry of Energy, 2019. *Handbook*. p.50-51
[19] Ministry of Energy, 2019. *Handbook*. p.54-57
[20] BP, 2019. *Statistical Review of World Energy*. p.41 and BP, 2020. Statistical Review of World Energy, p.43

Exports to Chinese Taipei (Taiwan) peaked at 5.5 bcma in 2004, before falling to 2.5 bcma since 2010, and dropping further to 1.6 bcma in 2018 and just 0.5 bcma in 2019. Exports to mainland China ('China East'), which began in 2009, have grown steadily to reach 6.7 bcma in 2018, before falling slightly to 6.2 bcma in 2019. These four destinations (Japan, South Korea, Taiwan, and China) have never accounted for less than 94 per cent of Indonesia's total LNG exports (94.4 per cent in 2019).

By contrast, since the launch of Indonesian exports to other markets in 2009, exports to any of those individual markets (Singapore, Thailand, Malaysia, India, UAE, Kuwait, Mexico, and Chile) have only once surpassed 0.4 bcma - the delivery of 1.95 bcm to Mexico in 2010. In 2017-2019, total annual exports to these markets ranged between 0.90 and 0.98 bcma.

**Figure 13: Indonesian LNG Exports**




Source: Data from the IEA (up to 2017) and BP (2018, 2019); Graph by the author [21]

## Internal Indonesian LNG Movements

In addition to LNG exports to other countries, Indonesian terminals export LNG to receiving terminals in other parts of Indonesia. This involves moving gas from the eastern part of the country (the Bontang, Tangguh, and Donggi-Senoro export terminals) to the western part of the country (the Arun, West Java, Lampung, and Benoa (Bali) import terminals). Given that launch of these import terminals (including the re-launch of Arun as an import terminal) occurred between 2012 and 2016, it is therefore not surprising to see 'Indonesia West' emerge as a destination for Indonesian LNG 'exports' since 2014, as illustrated by Fig.13 above. Such supplies ranged from 4.01 to 4.39 bcma of natural gas between 2016 and 2019.

When LNG production for 'internal' sales is combined with LNG production for export, the overall figures show Indonesian LNG production relatively stable at 22-26 bcma from 2012 to 2018, falling to 20.6 bcm in 2019.

[21] BP, 2019. *Statistical Review of World Energy*. p.40

## LNG Contracts

In contractual terms, the Group of Global Liquefied Gas Importers (GIIGNL) lists Indonesia as having 16.56 million tonnes per annum [mtpa] (22.5 bcma) of LNG supply contracts currently in force. These contracts are detailed in Figure 14 below. However, 3.1 mtpa (4.22 bcma) of those contractual volumes are covered by three contracts for moving gas from eastern Indonesia (the Bontang LNG export terminal) to western Indonesia – that is, internal trade movement within Indonesia. The recipients of these volumes are the Indonesian state-owned gas company, Pertamina, and the operator of the Jawa Barat (West Java) FSRU, Nusantara Regas. This leaves 13.46 mtpa (18.28 bcma) of export contracts currently in force.[22]

In terms of LNG purchases, Pertamina has contracts with Woodside and Cheniere for the purchase of a combined 2.12 mtpa from 2019/2020 to 2039/2040, in addition to a short-term contract with Cheniere for 0.2 mtpa that is set to expire in 2022.

As part of its portfolio balancing efforts, Pertamina also signed a deal with Total in 2016 that commits Total to buying 0.4 mtpa of Pertamina's offtake commitment with Cheniere at Corpus Christi from 2020, while in parallel, also from 2020, Total will draw on its portfolio supplies to provide Pertamina with "a volume growing over time from 0.4 to 1.0 million tonnes per year of LNG over a period of 15 years from 2020".[23] This deal with Total, combined with the sales contract with PPT Energy Trading, effectively reduces offtake commitment relative to Cheniere at Corpus Christi, with the volumes being passed on to Total and PPT Energy trading.

Then, in February 2019, Pertamina signed a further sale and purchase agreement with Anadarko (Mozambique LNG) for the receipt of 1 mtpa (1.36 bcma) for 20 years, from the launch of the terminal, which is expected in 2024.[24]

In the short-term (2020-2023), Pertamina has a variety of sales and purchase contracts that will form part of its portfolio management. From 2024 onwards, if Mozambique LNG launches on schedule, Pertamina will be committed to purchasing 3.52-3.92 mtpa of LNG from foreign sources until at least 2035.

Regarding deals that have yet to be fully contracted, in 2017, Pertamina signed a Heads of Agreement with ExxonMobil for the purchase of 1 mtpa for 20 years from 2025. Then, in 2018, Pertamina signed Memoranda of Understanding with Petrobangala, the Bangladesh Power Development Board, and Pakistan State Oil, with total sales by Pertamina to its Bangladeshi and Pakistani counterparts projected to be 2-3 mtpa.

The deals signed in 2016-17 possibly reflected expectations of a combination of stagnant production and rising domestic demand. However, as demand since then has proven weaker than expected, and Indonesia is not expected to require LNG imports to help meet both its domestic and export commitments until the mid-2020s, the agreements to re-sell offtake from Corpus Christi and the MoUs with Bangladeshi and Pakistani counterparts reflect portfolio management rather than an expansion of Indonesian LNG exports.

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[22] GIIGNL, 2019. *Annual Report: The LNG Industry in 2018*. https://giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_annual_report_2019-compressed.pdf. p.11.

[23] Total, 2016. Total signs long-term agreements to supply LNG to state-owned Indonesian company Pertamina. *Press Release*, 2 February. https://www.total.com/en/media/news/press-releases/total-signs-long-term-agreements-supply-lng-state-owned-indonesian-company-pertamina

[24] LNG World News, 2019. Anadarko signs Mozambique LNG SPA with Pertamina. *LNG World News*, 19 February. https://www.lngworldnews.com/anadarko-signs-mozambique-lng-spa-with-pertamina/

**Figure 14: Existing & Forthcoming Import/Purchase Contracts**

| New Import/Purchase Contracts | | | | | |
|---|---|---|---|---|---|
| **Source** | **Seller** | **Buyer** | **Start** | **End** | **Volume (ACQ mtpa)** |
| Portfolio | Chevron | Pertamina (Indonesia) | 2016 | 2022 | 0.2 |
| Portfolio | Woodside | Pertamina (Indonesia) | 2019 | 2039 | 0.6 |
| Corpus Christi T1 | Cheniere | Pertamina (Indonesia) | 2019 | 2039 | 0.76 |
| Corpus Christi T2 | Cheniere | Pertamina (Indonesia) | 2020 | 2040 | 0.76 |
| Portfolio | Total | Pertamina (Indonesia) | 2020 | 2035 | 0.4-1.0 |
| Mozambique LNG | Anadarko | Pertamina (Indonesia) | 2024 (est.) | 2044 | 1.0 |
| **Total** | | | | | **3.72-4.32** |

Source: Data from GIIGNL Annual Reports; Tables by the author

## Infrastructure: LNG terminals and pipelines

### Existing infrastructure

Indonesia began exporting LNG in 1977, when two export terminals were completed: Bontang (also known as Badak, after the name of its source field) and Arun. By 1984, Indonesia was the world's largest exporter of LNG. It held that title until 2006, when it was overtaken by Qatar. As recently as 2010, it retained second place, before falling behind Malaysia in 2011, and trailing to Australia and Nigeria in 2012.[25] Today, Indonesia is the 9th largest LNG exporter in the world.

The Bontang LNG export terminal in Kalimantan (the Indonesian part of the island of Borneo) was launched in August 1977. As production was ramped up, the plant grew from four to eight trains, reaching a combined capacity of 21.6 mtpa by 1999. The latter four trains were launched in 1990, 1994, and 1998 (x2). [26] However, production at Bontang (Badak) peaked at 21.4 mt in 2001, and has since fallen continuously to 5.77 mt (7.84 bcm) in 2019.[27] GIIGNL reports only the newest four trains as being active, with a combined output capacity of 11.5 mtpa.[28] The terminal remains 100 per cent owned by the Indonesian State Asset Management Agency, under the direction of the Finance Ministry, while the operator, Badak LNG, has Pertamina (55 per cent), VICO Indonesia (20 per cent), Pertamina Pedeve Indonesia (15 per cent), and Total E&P Indonesia (10 per cent) as its shareholders.[29] [30]

In northern Sumatra, the Arun terminal shipped its first cargo in October 1977. The terminal originally consisted of three trains, but was expanded to six trains by 1986 to reach a maximum capacity of 12.8 mtpa.[31] However, Arun field production peaked in 1994 and the terminal's export capacity was halved in 2001.[32] The terminal ceased its export operations in 2014, and was relaunched as an import terminal

[25] IGU, 2010. *World LNG Report*. http://members.igu.org/old/gas-knowhow/publications/igu-publications/IGU per cent20World per cent20LNG per cent20Report per cent202010.pdf p.6. See also later editions of IGU World LNG Report
[26] GIIGNL, 2019. *Annual Report: The LNG Industry in 2018*. https://giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_annual_report_2019-compressed.pdf. p.36
[27] Platts LNG
[28] GIIGNL, 2019. p.36.
[29] Badak LNG, 2020. *Shareholders*. http://portal.badaklng.co.id/index.php/38-shareholders
[30] Sulaiman, S.R., 2018. Government partners with Pertamina in Badak LNG plant. *The Jakarta Post*, 31 December. https://www.thejakartapost.com/news/2018/12/31/government-partners-with-pertamina-in-badak-lng-plant.html
[31] Oxford Business Group, 2010. *The Report: Indonesia*. https://books.google.co.uk/books?id=Pa0qLygOe14C&printsec=frontcover#v=onepage&q&f=false. Page 97.
[32] Oxford Business Group, 2010. Page 97.

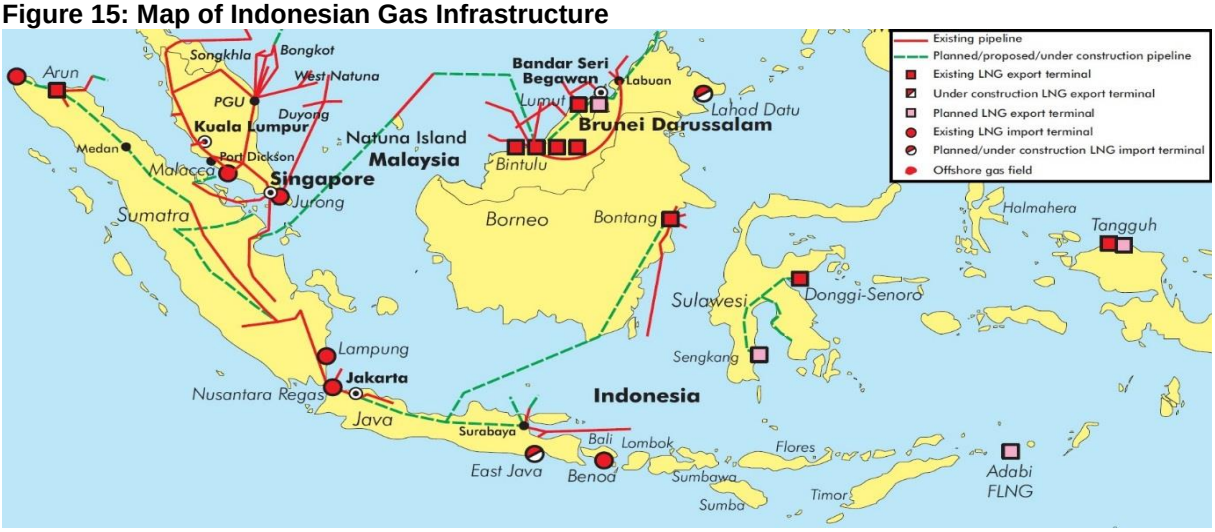
in March 2015, with a send-out capacity of 1.5 mtpa (2.1 bcma).[33] [34] Today, the Arun terminal is owned and operated by PT Perta Arun Gas, whose shareholders are Pertamina (70 per cent) and the regional Government of Aceh (30 per cent).[35] According to Platts, 0.75 mt of LNG (1,024 mmcm of natural gas) was imported via this terminal in 2019 – all sourced from Indonesian export terminals.

In February 2019, Pertamina and PPT Energy Trading (a 50-50 JV between Pertamina and a consortium of Japanese partners) reached an agreement on the use of Arun terminal for LNG storage and reloads. Arun has operated as a bonded warehouse since 2016. Only LNG from Indonesian terminals has been received and re-gasified since 2015, and from 2019 onwards, international cargoes will not be re-gasified and injected into the system, but reloaded and re-exported. As such, no import taxes will be paid on international supplies arriving at Arun, making it competitive as a regional LNG bulk-break and reloading hub.[36]

Indonesia's third LNG export terminal, Tangguh, was launched in 2009 in the Indonesian part of New Guinea. The operator and largest shareholder is the BP subsidiary, Tangguh LNG (40 per cent).[37] The terminal has two trains, with a reported capacity of 7.6 mtpa. [38] According to Platts LNG data, 12.09 mt of LNG (8.9 bcm of natural gas) was exported from this terminal in 2019.

Finally, Indonesia's newest LNG export terminal, Donggi-Senoro, was launched in 2015 on the island of Sulawesi. The terminal has one train and an output capacity of 2.0 mtpa.[39] The shareholders in the project are Sulawesi LNG Development (59.9 per cent), PT Pertamina Hulu Energi (29 per cent), and PT Medco LNG Indonesia (11.1 per cent). Sulawesi LNG development is a 75-25 JV between Mitsubishi and Kogas, giving them effective shares of 44.9 per cent and 14.975 per cent, respectively. PT Pertamina Hulu Energi is 98.7 per cent owned by PT Pertamina, making Pertamina the second-largest shareholder, with an effective share of 28.6 per cent.[40] According to Platts, 1.9 mt of LNG (2.59 bcm of natural gas) was exported from this terminal in 2019.

**Figure 15: Map of Indonesian Gas Infrastructure**




Source: IEA Natural Gas Information 2018

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[33] Jensen, F., 2014. Indonesia's Arun LNG project to ship final cargo, imports due soon. *Reuters*, 14 October. https://www.reuters.com/article/indonesia-lng-exports/indonesias-arun-lng-project-to-ship-final-cargo-imports-due-soon-idUSL3N0S93IG20141014

[34] Rambu Energy, 2015. President Jokowi inaugurates Arun LNG Regasification facility. *Rambu Energy*, 9 March. https://www.rambuenergy.com/2015/03/president-jokowi-inaugurates-arun-lng-regasification-facility/

[35] GIIGNL, 2019. pg. 42.

[36] Argus, 2019. Pertamina, PPT agree on Arun LNG terminal use. *Argus Direct*, 15 February.

[37] BP, 2019. *Tangguh LNG*. https://www.bp.com/en_id/indonesia/home/who-we-are/tangguh-lng.html

[38] GIIGNL, 2019. p.36.

[39] GIIGNL, 2019. p.36.

[40] PT Donggi-Senoro LNG, 2019. *Ownership structure*. https://www.donggisenorolng.co.id/about-us/ownership-structure/eng/

Therefore, at present, Indonesia has the liquefaction capacity to produce 21.1 mtpa of LNG. This is substantially above the 16.56 mtpa of LNG (domestic and export) supply contracts currently in force, and the 14-15 mt produced in 2019. Specifically, the 14.3 mt of LNG exports reported by Platts equates to 19.5 bcm of natural gas.

Indonesia's first dedicated LNG import terminal, the Jawa Barat FSRU (also known as West Java) was launched in 2012, with a regas capacity of 4.0 bcma (3.0 mtpa). That FSRU is owned by Golar LNG and chartered by PT Nusantara Regas. [41] Platts report 1.76 mt of LNG (2.4 bcm of natural gas) imports via this terminal in 2019.

Two years later, another FSRU – Lampung – was launched with a nominal send-out capacity of 2.4 bcm per year (1.76 mtpa). Lampung is owned by the Norwegian Hoegh LNG, and operated by the Indonesian PGN on a 20-year charter. The West Java and Lampung terminals were supplemented by the re-deployment of the Arun terminal. According to Platts, the terminal received 0.37 mt of LNG (500 mmcm of natural gas) in 2019.

Finally, the smaller Benoa (Bali) FSRU was launched in 2016 on the island of Bali, with a nominal send-out of 0.475 bcm per year (0.35 mtpa). Benoa is 50-50 owned by two Indonesian companies: JSK and Pelindo.[42] Platts report that the terminal received 0.2 mt of LNG (273 mmcm of natural gas) in 2019.

Therefore, in total, Indonesia now has the capacity to regasify around 6.6 mtpa (9.0 bcma) of LNG, with the majority of regasification currently occurring at West Java, while according to Platts data on LNG cargoes, Indonesian LNG imports in 2019 were 3.08 mt (4.2 bcm or natural gas).

In terms of pipelines within Indonesia, only the islands of Sumatra and Java (together home to more than 190m people from a total Indonesian population of 268m) are connected. This reflects the concentration of population on these two islands, and the related development of the gas distribution network, as illustrated in Figure 16.

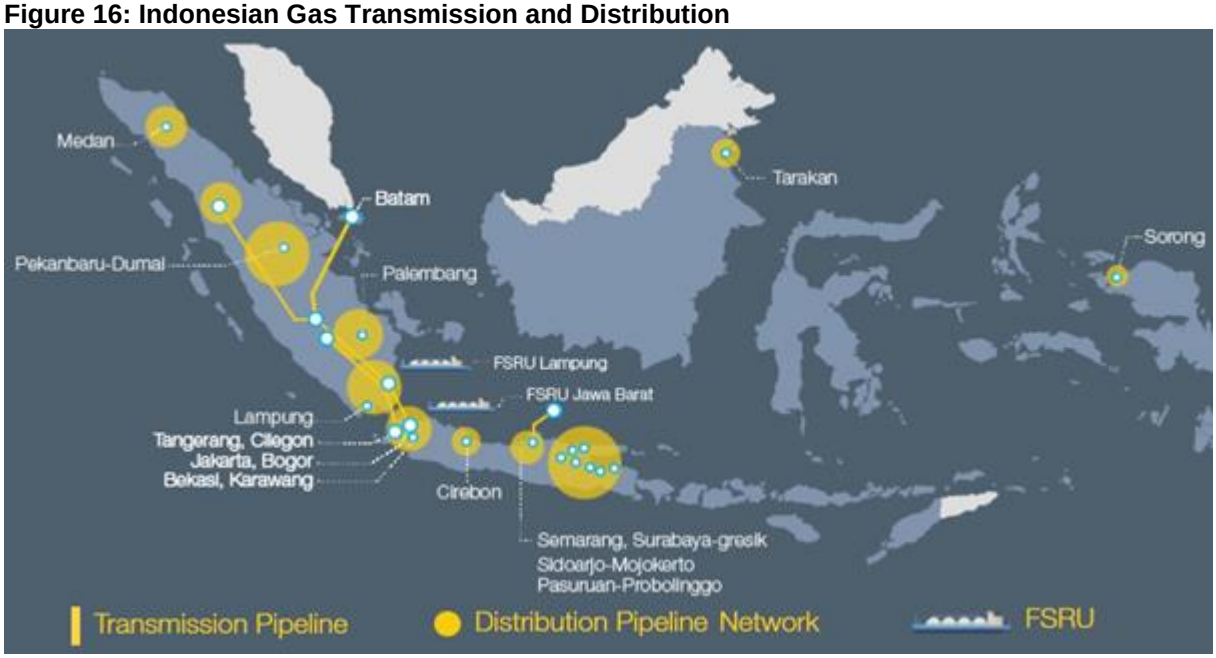
Regarding export pipelines, Indonesia is connected to Singapore (since 2001) and Malaysia (since 2003). Pipeline exports to Singapore peaked at 8.2 bcma in 2012, falling to 7 bcm in 2019. Pipeline exports to Malaysia also peaked in 2012, at 9.3 bcma, declined to 6.4 bcm in 2017, and fell dramatically to just 0.6 bcm in 2018 and 2019.[43]

[41] GIIGNL, 2019. p.42.

[42] GIIGNL, 2019. p.42.

[43] See Fig.4

**Figure 16: Indonesian Gas Transmission and Distribution**




Source: PGN[44]

## Planned infrastructure

The Tangguh LNG export terminal is undergoing expansion with the addition of a third train, due for launch in Q3 2021 – a year later than originally planned. That third train (3.8 mtpa) will take the plant's capacity to 11.4 mtpa (15.5 bcma).[45] In the first half of the 2020s, this will partially offset the decline in output at the Bontang export terminal.[46]

In June 2019, the Japanese E&P company, Inpex, and its project partner, Shell, submitted a revised Plan of Development (PoD) to the Indonesian government for a new, onshore, LNG export terminal and a related offshore gas production facility. That PoD was approved by the Indonesian Ministry of Energy and Mineral Resources. The project – Abadi LNG – reportedly has a Production Sharing Contract (PSC) valid until 2055, and a proposed capacity of 9.5 mtpa (12.9 bcma). Reports suggest that Inpex intends to take FID in the next 2-3 years, with start-up planned for the late 2020s.[47] [48] The facility was originally envisaged as an offshore floating LNG export terminal, but the Indonesian government has insisted on an onshore development, sourced from the offshore Abadi field. The addition of Tangguh T3 (3.8 mtpa) and Abadi LNG (9.5 mtpa) will raise Indonesia's liquefaction capacity to 34.4 mtpa (46.8 bcm) by 2030.

Meanwhile, Energy World Corporation (EWC) continues to work on its LNG facility at Sengkang, in South Sulawesi. EWC already produces gas from an onshore gas field, and uses that gas to supply the Sengkang power plant, which generates electricity for PLN, under a supply contract that is valid until September 2022. EWC intends to use its gas production at Sengkang to provide source gas for the LNG liquefaction facility that it is currently building – its PSC, for which an extension was signed in December 2018, runs from October 2022 to 2042. The liquefaction plant is planned to consist of four

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[44] PGN, 2019. *Natural gas infrastructure*. http://www.pgn.co.id/tentang-kami?lang=en.

[45] Reuters, 2019. BP's Tangguh LNG plant Train 3 to be delayed by a year – regulator. *Reuters*, 19 July. https://uk.reuters.com/article/uk-lng-indonesia-bp/bps-tangguh-lng-plant-train-3-to-be-delayed-by-a-year-regulator-idUKKCN1UE1BV

[46] IGU, 2019. *World LNG Report 2019*. https://www.igu.org/sites/default/files/node-news_item-field_file/IGU per cent20Annual per cent20Report per cent202019_23 per cent20loresfinal.pdf. p.32

[47] Offshore Energy Today, 2019. WoodMac: Revised plan for Abadi LNG gets approval, but project 'still faces several challenges'. *Offshore Energy Today*, 15 July. https://www.offshoreenergytoday.com/woodmac-revised-plan-for-abadi-lng-gets-approval-but-project-still-faces-several-challenges/

[48] https://www.lngworldnews.com/inpex-shell-submit-revised-abadi-lng-plan-of-development/

modules, each producing 0.5 mtpa of LNG. In November 2018, EWC reported the LNG facility as being '80 per cent complete', although the facility has since been subject to rolling delays and its completion date is not confirmed.[49] [50] [51]

Regarding regasification capacity, another FSRU is due for launch by the end of 2021. The as-yet-unnamed vessel is on order for PT Jawa Satu Regas (JSR). The FSRU is part of the first integrated 'LNG-to-Power' project in Asia, and will supply gas to a 1,760 MW combined cycle gas-powered generation plant in West Java, which will be operated by PT Jawa Satu Power (JSP). Both JSR and JSP are subsidiaries of PT Pertamina Power Indonesia (PPI), a holding company that is acting as the lead in a consortium with Japanese partners, Marubeni and Sojitz.[52] The FSRU will have a storage capacity of 170,000 $m^3$ of LNG (the same as the Lampung FSRU), and regasification send-out of 8.5 mmcm/d (equivalent to 3.1 bcma), while GIIGNL reports its LNG reception capacity as 2.4 mtpa.[53]

On a smaller scale, PGN is currently building a small LNG regas terminal at the port of Teluk Lamong in East Java. Reports suggest that the terminal will have an initial regasification capacity of 0.85 mmcm/d (310 mmcm per year), rising to 5 mmcm/d (1.86 bcm per year) by 2023. While a floating storage unit (FSU) will be leased for the first stage of the project, a permanent 50,000 $m^3$ storage tank is planned for construction in the final phase.[54] In March 2020, it was reported that the initial stage of the terminal was '90 per cent complete' and that testing was due to begin in May 2020.[55] If these projects are completed as planned, Indonesia could have 13.96 bcma of regasification capacity by the end of 2023.

## Government Policy and Regulation

### Historical context

The first state-owned Indonesian oil company, Permina, began its activities in 1957. Then, in 1960, the government passed Law 44, which stated that foreign companies (such as BPM, Caltex, and Stanvac) were no longer concession holders, but contractors providing services to Indonesian state-owned companies, with the Indonesian state accordingly taking a share of the profits from such activity. After several years of negotiation, in 1963 it was finally agreed that "Shell, Stanvac, and Caltex, the major foreign oil companies operating in Indonesia, were to become contractors of Permigan, Permina, and Pertamin, respectively. The foreigners would retain management of the oil installations, but 60 per cent of profits from all activities would go to Indonesia".[56]

In 1965, two state-owned companies were established: PGN (National Gas Company) and PLN (State Electricity Company) to manage the gas and electricity transmission networks. Today, both companies

[49] EWC, 2018. *Projects*. http://www.energyworldcorp.com/projects.php
[50] LNG World News, 2018. EWC edges forward with its red-tape hampered LNG projects. *LNG World News*, 29 November. https://www.lngworldnews.com/ewc-edges-forward-with-its-red-tape-hampered-lng-projects/
[51] LNG World News, 2019. Energy World Corp. to boost gas supply to Sengkang power plant. *LNG World News*, 8 July. https://www.lngworldnews.com/energy-world-corp-to-boost-gas-supply-to-sengkang-power-plant/
[52] Pertamina, 2018. Pertamina Enters the Construction Phase of the Integrated Project of the FSRU and the Java-1 1760 MW Power Plant. *Press Release*, 8 December. https://www.pertamina.com/en/news-room/news-release/pertamina-memasuki-tahap-konstruksi-proyek-terintegrasi-fsru-dan-pembangkit-listrik-jawa-1-1760-mw
[53] World Maritime News, 2018. MOL to Take Part in Indonesia's Jawa 1 FSRU Project. *World Maritime News*, 7 December. https://worldmaritimenews.com/archives/266226/mol-to-take-part-in-indonesias-jawa-1-fsru-project/
[54] Indrawan, R., 2019. Amankan Pasokan Gas Terminal Teluk Lamong, PGN Cari Tambahan Kargo LNG (Securing the Supply of Gas in the Teluk Lamong Terminal, PGN seeks additional LNG cargo), *Dunia Energi*, 19 September. https://www.dunia-energi.com/amankan-pasokan-gas-terminal-teluk-lamong-pgn-cari-tambahan-kargo-lng/
[55] CNBC Indonesia, 2020. PGN Trial of Teluk Lamong LNG Terminal in May 2020. *CNBC Indonesia*, 19 March. https://www.cnbcindonesia.com/market/20200319193128-17-146280/pgn-uji-coba-terminal-lng-teluk-lamong-pada-mei-2020
[56] Vlessing, E., 2006. *International Directory of Company Histories: Pertamina*. https://www.encyclopedia.com/social-sciences-and-law/economics-business-and-labor/businesses-and-occupations/pertamina [Accessed 9 August 2019].

are active throughout the value chain, from upstream gas production and power generation, through midstream transmission, to downstream distribution and retail.[57] [58]

In 1966, the Indonesian government agreed to purchase all of Shell's assets in Indonesia over the next five years. Two years later, Pertamin and Permina merged to become Pertamina. Then, in 1971, new legislation stipulated that only Pertamina could extract oil and natural gas in Indonesia.[59] [60] This was the context when the Arun and Badak natural gas fields were discovered by Mobil and Huffco (respectively) in 1971. Once developed, these two fields would provide gas for the Arun and Bontang LNG export terminals.

### Sector governance

The Indonesian gas sector is governed by the Directorate-General for Oil and Gas, one of four DGs in the Ministry of Energy and Mineral Resources. Since 2008, the National Energy Council (NEC) has served as the "coordinator for the design and formulation of energy policy, to decide measures to manage energy crises and emergencies, and to monitor the implementation of cross-sectoral energy policy". The House of Representatives (the lower chamber of Indonesia's bicameral parliament) also plays a key role in formulating national energy policy, through its Commission VII, which is "responsible for energy, mineral resources, research and technology, and environmental matters. This responsibility includes oversight of all oil and gas activities. It drafts oil- and gas-related legislation, controls elements of state budgets and parts of related government policy. The Commission provides suggestions to government in relation to the oil and gas sector's contributions to the state budget".[61]

The upstream is regulated by the state regulator, SKK Migas, and governed by Production Sharing Contracts (PSCs). Under the terms of these PSCs, the producers must supply at least 25 per cent of the gas produced to the domestic market. This is referred to as the Domestic Market Obligation (DMO). The after-tax split between the government and contractor is 70:30. SKK Migas has responsibility for signing, managing, and monitoring the PSCs.[62]

The downstream has been regulated by BPH Migas since 2002. As the IEA notes:

> "It [BPH Migas] is responsible for ensuring sufficient natural gas and domestic fuel supplies and the safe operation of refining, storage, transport and distribution of gas and petroleum products via business licences. It is also responsible for the supervision of the transport of gas through pipelines. Companies active in the downstream sector are required to operate through an Indonesian-incorporated entity, known as a PT Company, and to have acquired a business licence (issued by MEMR, with input from BPH Migas)". [63]

The IEA goes on to state that the downstream gas sector is dominated by two companies. The first, PT Pertamina Gas (Pertagas), is a wholly-owned subsidiary of PT Pertamina, the state-owned oil and gas company. The second is PT Perusahaan Gas Negara (PGN), the owner-operator of the gas transmission network. PT Pertamina is a 57 per cent shareholder in PGN. The remaining 43 per cent of shares are owned by private investors, although no individual shareholder owns more 3.75 per cent.[64]

Regarding foreign companies active in the Indonesian gas sector, the Tangguh LNG terminal is operated by BP, and the Tangguh PSC Contractor Parties are BP (40 per cent shareholding), MI Berau B.V. (16.30 per cent), CNOOC Muturi Ltd. (13.90 per cent), Nippon Oil Exploration (Berau) Ltd. (12.23 per cent), KG Berau Petroleum Ltd (8.56 per cent), KG Wiriagar Petroleum Ltd. (1.44 per cent),

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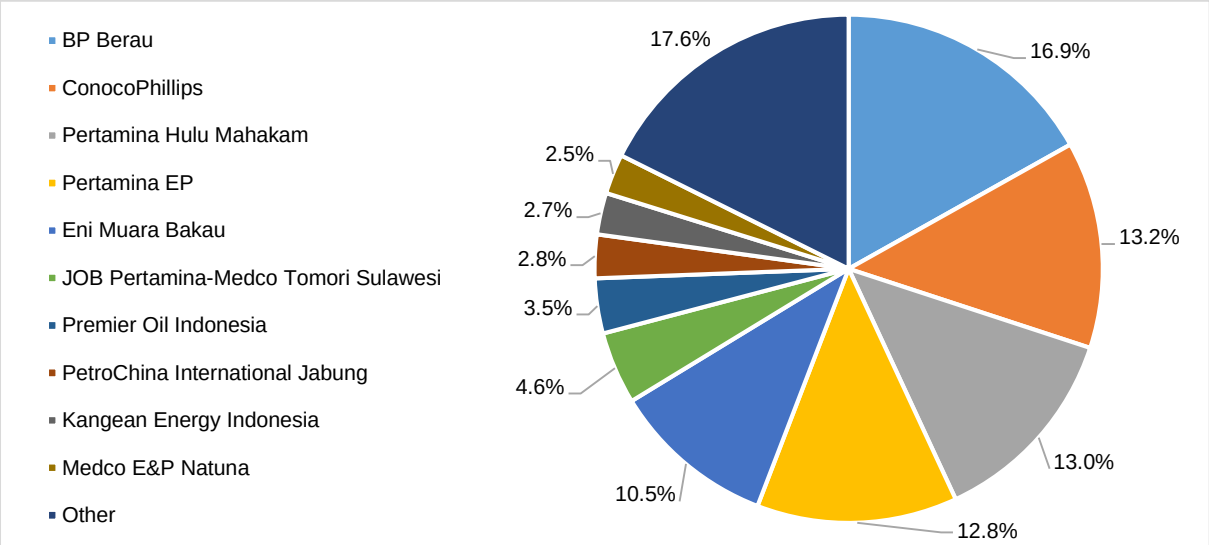
[57] PGN, 2019. *About us*. https://pgn.co.id/tentang-kami
[58] PLN, 2019. *Statistics 2018 (English)*. https://www.pln.co.id/statics/uploads/2019/07/STATISTICS-English-26.7.19.pdf
[59] Pertamina, 2019. *Who we are*. https://www.pertamina.com/en/who-we-are
[60] Vlessing, E., 2006. *International Directory of Company Histories: Pertamina*. https://www.encyclopedia.com/social-sciences-and-law/economics-business-and-labor/businesses-and-occupations/pertamina [Accessed 9 August 2019].
[61] IEA, 2015. *Indonesia In-Depth Review*. https://www.iea.org/publications/freepublications/publication/Indonesia_IDR.pdf. p.44
[62] IEA, 2015. *Indonesia In-Depth Review*. p.44-45
[63] IEA, 2015. *Indonesia In-Depth Review*. p.45
[64] PGN, 2019. *Our shareholders as of 30 June 2019*. http://ir.pgn.co.id/our-shareholders

Indonesia Natural Gas Resources Muturi Inc. (7.35 per cent).[65] As the table of LNG contracts notes, at the Bontang LNG terminal, Pertamina's foreign partners in LNG export contracts are Inpex (Japan), Eni (Italy), Total (France), and the developer of the IDD Bangka project, Chevron (US). Meanwhile, at Donggi-Senoro, Pertamina works in partnership with Mitsubishi and Kogas. Gas production by company (share of the total) is distributed according to the graph below.

**Figure 17: Indonesian Gas Production by Company in 2018 (Share of Total)**




Source: Data from PWC; Graph by the author[66]

Finally, a major consumer of gas in Indonesia is the vertically-integrated power sector utility, PLN. According to the IEA:

> "PT Perusahaan Listrik Negara (PLN) is the vertically integrated state-owned utility, which is responsible for the management and development of generation, transmission and distribution in Indonesia. PLN controls nearly all distribution of electricity in the country and holds a near monopoly on transmission and distribution grids in its concession area. PLN also has the right of first refusal on all new generation capacity. PLN is owned by the state and supervised from a technical perspective by the Ministry of Energy and Mineral Resources (MEMR) and from a management perspective by the Ministry of State-Owned Enterprises". [67]

Taken together, it is clear that the development and management of Indonesia's gas sector has been strongly state-led, with several state-owned companies under the auspices of the Indonesian Ministry of Energy and Mineral Resources working in partnership with foreign investors.

## Current issues

For several decades, the Indonesian gas industry was dominated by state-owned Pertamina and PGN. The industry was partially liberalised in 2001, when Law 44 (1960) and Law 8 (1971) were revoked by Law 22 of 22 November 2001 ('The Oil and Gas Law'). Under Law 22, upstream activities are controlled

[65] BP Indonesia, 2019. *Tangguh LNG*. https://www.bp.com/en_id/indonesia/home/who-we-are/tangguh-lng.html
[66] PWC, 2019. *Oil and Gas in Indonesia: Investment and Taxation Guide*. 10th edition (September 2019). https://www.pwc.com/id/en/energy-utilities-mining/assets/oil-and-gas/oil-gas-guide-2019.pdf p.19
[67] IEA, 2015. *Indonesia In-Depth Review*. p.102

by Joint Cooperation Contracts (mostly Production Sharing Contracts - PSCs) between the investor and the Indonesian agency, SKK Migas.[68] [69]

A key issue in Indonesia's gas production is the division of roles between state-owned Pertamina and other, private investors. On the 1st of January 2018, Pertamina took over operatorship of the Mahakam block from Total. The block is located in Kalimantan and supplies the Bontang LNG export terminal. But in May 2019, the Indonesian regulator, SKK Migas, called on Pertamina to accelerate its investment because the company was failing to meet its gas production targets at the block. Between January and April 2019, Pertamina had produced 18.9 mmcm/d (equivalent to 6.9 bcma), which was only 61 per cent of its government-mandated target.[70] In the oil sector, Pertamina was also chosen to take over operatorship of Indonesia's second-largest oil-producing block, Rokan, when Chevron's PSC expires in 2021.[71]

Finally, in August 2019, the Indonesian government awarded Pertamina operatorship of the Corridor gas block in South Sumatra, once the PSC held by the operator, ConocoPhillips, and its partner, Repsol, expires in 2023. The Corridor Block is reportedly the second-largest gas-producing block in Indonesia, with production potential of 23.4 mmcm/d in H1 2019 (equivalent to 8.5 bcma).[72]

However, unlike the contractual changes noted above, ConocoPhillips and Repsol will retain stakes in the block: ConocoPhillips will see its share fall from 56 per cent to 46 per cent and Repsol will see its share fall from 36 per cent to 24 per cent, while Pertamina will see its share rise from 10 per cent to 30 per cent. The shares of ConocoPhillips and Repsol will fall further, as they are obliged to offer 10 per cent from their combined share to local state-owned companies. In a sign that the Indonesian government has learnt its lesson from the performance of Pertamina at Mahakam, ConocoPhillips will also continue to operate the project for the first three years of the new PSC (2023-2026).[73]

## Supply / Demand Projections

### Gas production forecasts

Indonesian gas production peaked in 2010, and, after falling sharply in the two years that followed, has been declining slowly since 2012. However, several new production projects are set to boost Indonesian gas production from the mid-2020s, compensating for the gradual declines at existing fields.

Firstly, Eni launched production at the Jangkrik gas field (part of the Muara Bakau PSC) in May 2017, for delivery to either domestic or export markets from the Bontang LNG terminal. Production there is currently ramping up to 12.7 mmcm/d (4.7 bcma)[74] and this may help offset the under-performance of Pertamina at Mahakam in providing supplies for the Bontang LNG terminal. The first shipment of Jangkrik-produced gas from Bontang LNG took place in June 2017.[75]

Secondly, Eni is also developing the Marekes offshore gas field (part of the East Sepinggan PSC), with investment sanctioned by the company's Board of Directors in December 2018. According to Eni, the

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[68] PWC, 2018. *Oil and Gas in Indonesia: Investment and Taxation Guide (9th Edition – May 2018)*. https://www.pwc.com/id/en/energy-utilities-mining/assets/oil-and-gas/oil-and-gas-guide-2018.pdf. p.26

[69] WKMIGAS, 2009. LAW NO. 22/2001 DATED NOVEMBER 23, 2001: CONCERNING OIL AND GAS. http://www.wkmigas.com/wkcbm/wp-content/uploads/2009/10/01.Law_Of_The_Republic_Of_Indonesia_Number_22_Of_2001.pdf

[70] Setiawatan, V., 2019. Oil and Gas Lifting Has Not Yet Reached Target, Pertamina Asked to Accelerate Investment. *Katadata*, 9 May. https://katadata.co.id/berita/2019/05/09/lifting-migas-belum-capai-target-pertamina-diminta-percepat-investasi

[71] Argus, 2018. Chevron to lose Indonesia's Rokan oil block. *Argus Direct*, 1 August.

[72] Sulaiman, S., 2019. Watch and learn: Government lectures Pertamina on block operatorship. *Jakarta Post*, 8 August. https://www.thejakartapost.com/news/2019/08/06/watch-and-learn-govt-lectures-pertamina-on-block-operatorship.html

[73] Argus, 2019. Jakarta's upstream reclamation hits constraints. *Argus Direct*, 2 August.

[74] Eni, 2017. Eni starts production from Jangkrik Project, deep offshore Indonesia, ahead of schedule. *Press Release*, 15 May. https://www.eni.com/en_IT/media/2017/05/eni-starts-production-from-jangkrik-project-deep-offshore-indonesia-ahead-of-schedule

[75] Eni, 2017. Eni ships its first LNG cargo from Jangkrik. *Press release*, 22 June. https://www.eni.com/en_IT/media/2017/06/eni-ships-its-first-lng-cargo-from-jangkrik

field has 56.6 bcm of reserves, although the Indonesian Energy Ministry estimates it at 23 bcm. Initial production is estimated at 4.4 mmcm/d (1.6 bcma) in 2021 rising to 11.1 mmcm/d (4.1 bcma).[76] Also in December 2018, Eni announced the discovery of additional resources at Marekes East with potential production of 2 mmcm/d (0.73 bcma).[77] This takes the total potential new Eni production at Marekes to around 4.8 bcma by the mid-2020s, with this supply also likely to be directed to the Bontang LNG terminal. If the Indonesian Energy Ministry is correct in its assessment of reserves at Marekes, this production should cease around 2030, or the mid-2030s based on Eni's estimate.

Thirdly, in August 2019, Eni (40 per cent), Pertamina (30 per cent), and Neptune (30 per cent) were awarded the West Ganal PSC, with Eni as the operator. West Ganal includes the Maha field, which has resources estimated at 17 bcm.[78] No announcement has yet been made regarding the timeline for the development of the block, nor its proposed annual production volumes. Bontang is the nearest liquefaction plant and a possible outlet for the gas that is produced at West Ganal.

Fourthly, in February 2019, Repsol announced the discovery of a new onshore gas field at its Sakakemang PSC in central Sumatra, also with estimated reserves of 2 trillion cubic feet (56.6 bcm).[79] IHS-Markit estimate production of 7.6 mmcm/d (2.8 bcma) for 20 years from 2024.[80] However, it remains unclear how the resource will be exploited, and how the production volumes will affect Indonesia's gas balance.

Finally, as part of its Indonesian Deepwater Development (IDD) project, Chevron began gas production at the Bangka field in 2016 (where it holds a 62 per cent stake in partnership with Eni and Sinopec), and is working towards FID at the related Gendalo and Gehem fields. Those fields are located in East Kalimantan, for supply via the Bontang LNG terminal. In August 2020, there remains some doubt over the IDD project with Chevron announcing its intention to withdraw and the government in talks with Eni to take over operatorship.[81] While the Bangka field has a production capacity of 1.1 bcma, the Gendalo-Gehem project has a potential production capacity of 11.4 bcma, which will be supplied to the Bontang LNG terminal.[82]

Therefore, by the mid-2020s, the new fields brought online by Eni and Repsol could add 7.8 bcma plus the ramp-up at Eni's Jangkrik field, and a potential 11.4 bcma from the Gendalo-Gehem project – a total of over 19.2 bcma. The majority of these volumes will be brought to the domestic or export markets via the Bontang LNG terminal, thus countering the ongoing decline of LNG production at that terminal due to declining gas production at its source fields. To this will also likely be added volumes from the Abadi LNG (and related offshore gas production) project, which aims to launch in 2028 with a projected liquefaction capacity of 9.5 mtpa (12.9 bcm), and more modest volumes from the West Ganal PSC.

Given that the new production projects discussed above could add almost 20 bcma to the existing production level by the mid-2020s, the offsetting effect of a modest decline at other fields means that Indonesian gas production could feasibly rise from its current level of 74 bcma to around 90 bcm by the

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[76] Reuters, 2018. Eni's Indonesia gas project to start up in 2021 under new contract: deputy minister. *Reuters*, 4 December. https://www.reuters.com/article/us-indonesia-eni-merakes/enis-indonesia-gas-project-to-start-up-in-2021-under-new-contract-deputy-minister-idUSKBN1O31B7

[77] Eni, 2018. Eni announces Merakes East Gas discovery in the Indonesian offshore. *Press Release*, 19 December. https://www.eni.com/en_IT/media/2018/12/eni-announces-merakes-east-gas-discovery-in-the-indonesian-offshore

[78] Eni, 2019. Eni awarded West Ganal Exploration Block in the Kutei Basin Indonesia. *Press Release*, 26 August. https://www.eni.com/en_IT/media/2019/08/eni-awarded-west-ganal-exploration-block-in-the-kutei-basin-indonesia

[79] Repsol, 2019. Repsol has made the largest gas discovery in Indonesia in the past 18 years. *Press Release*, 19 February. https://www.repsol.com/en/press-room/press-releases/repsol-makes-largest-gas-discovery-indonesia-past-eighteen-years.cshtml COULDN'T OPEN THIS ONE

[80] Chatterji, G., 2019. Largest gas discovery in Indonesia in 18 years could reduce Indonesia's LNG demand by up to 2 MMtpa. *IHS Markit*, 27 February. https://ihsmarkit.com/research-analysis/largest-gas-discovery-in-indonesia-in-18-years.html

[81] Jakarta Post, 7 August 2020 "As Chevron exit looms Indonesia eyes Eni to take over IDD megaproject" .https://www.thejakartapost.com/news/2020/08/07/as-chevron-exit-looms-indonesia-eyes-italian-eni-to-take-over-idd-gas-megaproject.html

[82] Offshore Technology, 2019. *Indonesia Deepwater Development, Kutie Basin*. https://www.offshore-technology.com/projects/indonesia-deepwater-development-kutie-basin/

mid-to-late 2020s. Taking into account the possibility of delays at the new production projects, the achievement of 90 bcma of production by 2030 is a reasonable forecast.

Maintaining those production levels in the longer term through to 2040 will be more challenging, as existing production at other fields declines. Beyond the Abadi LNG project, future production will therefore depend on either the exploitation of further discoveries or an increase in non-conventional gas production, as the IEA notes in their 2017 World Energy Outlook:

> "With resources of almost 15 trillion cubic metres, a third of which are unconventional gas resources (mostly coalbed methane and shale gas), the country is not short of gas but developing large new projects such as East Natuna (Asia's largest untapped gas field, located in the Natuna Sea off the coast of Western Kalimantan) becomes increasingly challenging… Key contributions to Indonesia's output growth come from the "Indonesia Deepwater Development" project (located off the coast of Eastern Kalimantan) and tapping of the country's significant coalbed methane resources, mostly located in Eastern Kalimantan and Sumatra".[83]

In this context, forecasts by the Indonesian government's National Energy Council (NEC), the Asia-Pacific Economic Cooperation Energy Working Group (APEC EWC), and International Energy Agency (IEA) offer diverging forecasts for the future of Indonesian gas production.

In January 2019, the Indonesian National Energy Council published its latest *Indonesia Energy Outlook*.[84] The Outlook covers three scenarios: Business as Usual, Sustainable Development (SD), and Low Carbon (LC). In all three scenarios, Indonesian gas production rises from 75.4 mtoe (77.75 bcm) in 2018 to around 89 mtoe (91.78 bcm) in 2020, before falling to around 66.3 mtoe (68.37 bcm) in 2030. By 2040, gas production is forecast to rise slightly, to around 72 mtoe (74.25 bcm), before falling back to around 66 mtoe (68.06 bcm) in 2050.

The starting point for the *Outlook* – the figure for production in 2018 – is slightly different from the figure published by the Indonesian Ministry for Energy and Mineral Resources in its *Handbook of Energy and Economic Statistics for Indonesia* for net gas production in 2018 (72.6 bcm or 70.4 mtoe).[85] According to the data in the *Handbook*, the difference between gross and net gas production is accounted for by gas consumption during gas lifting, reinjection, and flaring. When the losses due to lifting and reinjection are included (but flaring excluded), the figure in the Energy Ministry *Handbook* rises to 77.2 bcm – similar to that stated in the NEC Outlook for production in 2018.

In contrast to the waves of growth and decline forecast by the NEC, the *APEC Energy Demand and Supply Outlook*, published in May 2019, forecasts that 'gas production is almost unchanged over the Outlook period at 64 Mtoe [66 bcm] per year'.[86] This forecast appears to be based on net gas production, but with a lower figure for gas production in 2018 than the figure stated by the Indonesian Ministry for Energy and Mineral Resources in its *Handbook*.

Finally, the IEA World Energy Outlook 2018 (New Policies Scenario) forecasts continuous growth in Indonesian gas production, from 74 bcm in 2017 to 80 bcm in 2025, 82 bcm in 2030, 89 bcm in 2035, and 100 bcm in 2040.[87] By taking production of 74 bcm in 2017 as its starting point, this forecast is also based on net gas production, and is similar to the starting point offered by the Energy Ministry *Handbook*. As the extended quote above suggests, the IEA foresees long-term Indonesian gas

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[83] IEA, 2017. *World Energy Outlook 2017 Special Report: South-East Asia Energy Outlook*. p.83
[84] NEC, 2019. *Indonesia's Energy Outlook 2019 (September 2019)*. https://www.den.go.id/index.php/publikasi/index/EnergyOutlook. p.3-4.
[85] Ministry of Energy & Mineral Resources of the Republic of Indonesia, 2019. *Handbook of Energy & Economic Statistics of Indonesia (January 2019)*. https://www.esdm.go.id/assets/media/content/content-handbook-of-energy-and-economic-statistics-of-indonesia-2018-final-edition.pdf. p.84
[86] APEC Energy Working Group, 2019. *APEC Energy Demand and Supply Outlook. 7th Edition – Vol. II*. https://www.apec.org/Publications/2019/05/APEC-Energy-Demand-and-Supply-Outlook-7th-Edition---Volume-II. p 131
[87] IEA, 2018. *World Energy Outlook 2018*. p.179

production being at least partially supported by deep-water and unconventional (particularly coalbed methane) production.

In light of the projects discussed above, the strongest growth in Indonesian gas production is likely to take place between 2025 and 2030, while the maintenance (or even further growth) of those production levels through to 2040 is dependent on the exploitation of large, new discoveries or unconventional gas resources, such as coalbed methane. Therefore, a conservative forecast predicts moderate growth between 2020 and 2025, stronger growth between 2025 and 2030, a slowdown in growth between 2030 and 2035, and then a gradual decline between 2035 and 2040. However, that future slowdown and decline could be offset by the development of new offshore fields or substantial non-conventional gas production, with the forecast to be revised accordingly once those new developments begin.

### Forecasts for Indonesian gas demand

The National Energy Council *Outlook* serves as the official forecasts for the Indonesian government, and is the most detailed (and most bullish) publicly-available forecast for Indonesian energy demand. It is based on a combination of annual GDP growth of 5.6 per cent per year for the duration of the forecast and substantial population growth of 0.7 per cent per year. While the latter may not sound substantial, in a country with a population of around 265 million in 2018, this rate of growth takes the population to 288 million in 2030 (+23m) and 309 million in 2040 (+44m).[88] Aligned to this, per capita electricity consumption is forecast to grow by a factor of 4.7, rising by 2040 to a level similar to that of China or Malaysia in 2017.[89]

The *Outlook* takes as its starting point total final energy demand of 114 million tonnes of oil equivalent (mtoe) in 2018. The shares of energy consumption by sector were transportation (40 per cent), industry including power generation (36 per cent), households (16 per cent), commercial (6 per cent), and other sectors (2 per cent).[90] By this classification, gas is visible only in the 'industrial' sector, based on gas consumption for power generation and final gas consumption in industrial processes. This concentration of gas in the 'industrial' classification remains unchanged throughout the forecast period.

From this starting point, the Business as Usual scenario forecasts total Indonesian primary energy demand to grow dramatically to 129 mtoe (2020), 220 mtoe (2030), and 349 mtoe (2040). The share of gas in total primary energy demand is expected to remain at 28 per cent from 2018 to 2020, before falling to (and remaining at) 24 per cent from 2025 to 2050.[91] This suggests that total primary gas demand is forecast to be 62.6 mtoe (64.5 bcm) in 2020, 75.2 mtoe (77.6 bcm) in 2025, 96.2 mtoe (99.2 bcm) in 2030, 121.2 mtoe (125.0 bcm) in 2035, and 150.9 mtoe (155.6 bcm) in 2040.

Industrial sector final energy demand is forecast to rise from 45 mtoe in 2020, 58.2 mtoe (2025), 75.6 mtoe (2030), 99.6 mtoe (2035), up to 131.2 mtoe (2040). Gas is forecast to retain the largest share of any fuel. In 2018, the share of gas in industrial sector final energy demand is estimated at 42 per cent. This share is forecast to decline to 39 per cent (2020), 38 per cent (2030), and 35 per cent (2040).[92] When the absolute growth in overall industrial sector final energy demand is considered, this equates to gas demand of 17.6 mtoe (2020), 28.7 mtoe (2030), and 45.9 mtoe (2030). This is the equivalent of 18.1 bcm (2020), 29.6 bcm (2030), and 47.3 bcm (2040) – Up from 15 bcm in 2018.

Within final energy demand in the industrial sector, gas, coal, and electricity retain relatively separate functions. According to the *Outlook*:[93]

> *Natural gas and coal are still the main energy sources in the industrial sector until 2050. Natural gas is most widely used to meet the demand of the metal, fertilizer (as raw material)*

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[88] NEC, 2019. Outlook. p.12
[89] IEA, 2019. *Energy Atlas: Electricity Consumption per Capita in 2017 (MWh/capita)*. http://energyatlas.iea.org/#!/tellmap/-1118783123/1
[90] NEC, 2019. Outlook. p.1
[91] NEC, 2019. Outlook. p.36
[92] NEC, 2019. Outlook. p.24
[93] NEC, 2019. Outlook. p.23

*and ceramics industries. The three industries consume around 83 per cent of natural gas from the total demand for natural gas in the industrial sector. While most coal (90 per cent) is consumed by the cement industry.*

Therefore, as total energy demand in the industrial sector grows, demand for gas will also grow due to a relative lack of 'switchability' in the three industries in which gas demand is concentrated.

In the power sector, primary production of electricity is forecast to rise from 284 TWh (2018) to 379 TWh (2020), 648 TWh (2025), 939 TWh (2030), 1,265 TWh (2035), and 1,634 TWh (2040). Once losses are taken into account, total electricity demand is forecast to grow rapidly from 255 TWh in 2018 to 339 TWh (2020), 576 TWh (2025), 833 TWh (2030), 1,119 TWh (2035) and 1,437 TWh (2040) – an average growth rate of 7 per cent per year. By 2040, household electricity demand is forecast at 900 TWh, industry at 275 TWh, and commercial at 200 TWh, while demand in the transport and 'other' sectors is negligible. This growth in household-sector electricity demand is driven by a population growth and rising per-capita energy consumption. By 2040, per-capita electricity consumption is forecast at 4,600 TWh per year – up from just under 1,000 TWh per year in 2018.[94]

In meeting this huge growth in demand, gas will face competition from coal and renewables. In 2018, gas accounted for 29 per cent of installed power generation capacity, and 20.2 per cent of power generation. By contrast, coal accounted for 50 per cent of generation capacity and 56.4 per cent of actual generation, renewables accounted for 14 per cent of installed capacity and 17.1 per cent of generation, with the remaining power generation accounted for by fuel oil (6.3 per cent).[95]

Under the Business as Usual scenario, in 2020 the shares in power generation are forecast as: Coal (60 per cent – 228 TWh), gas (28 per cent – 105 TWh), and renewables (12 per cent – 46 TWh), with total power generation of 379 TWh. By 2040, total power generation is forecast to rise to 1,634 TWh, while the forecast shares are: Coal (43 per cent – 703 TWh), gas (30 per cent – 490 TWh), and renewables (27 per cent – 441 TWh).[96] Therefore, gas–fired power generation is forecast to grow 8.6 times between 2018 (57 TWh) and 2040 (490 TWh). Given gas demand of 15.3 bcm for power generation in 2018, this implies gas demand for power generation of 131.6 bcm by 2040 (improvements in power generation efficiency notwithstanding). In between, a straight-line growth pattern suggests gas demand for power generation of 25.9 bcm (2020), 52.3 bcm (2025), 78.7 bcm (2030), and 105.2 bcm (2035).

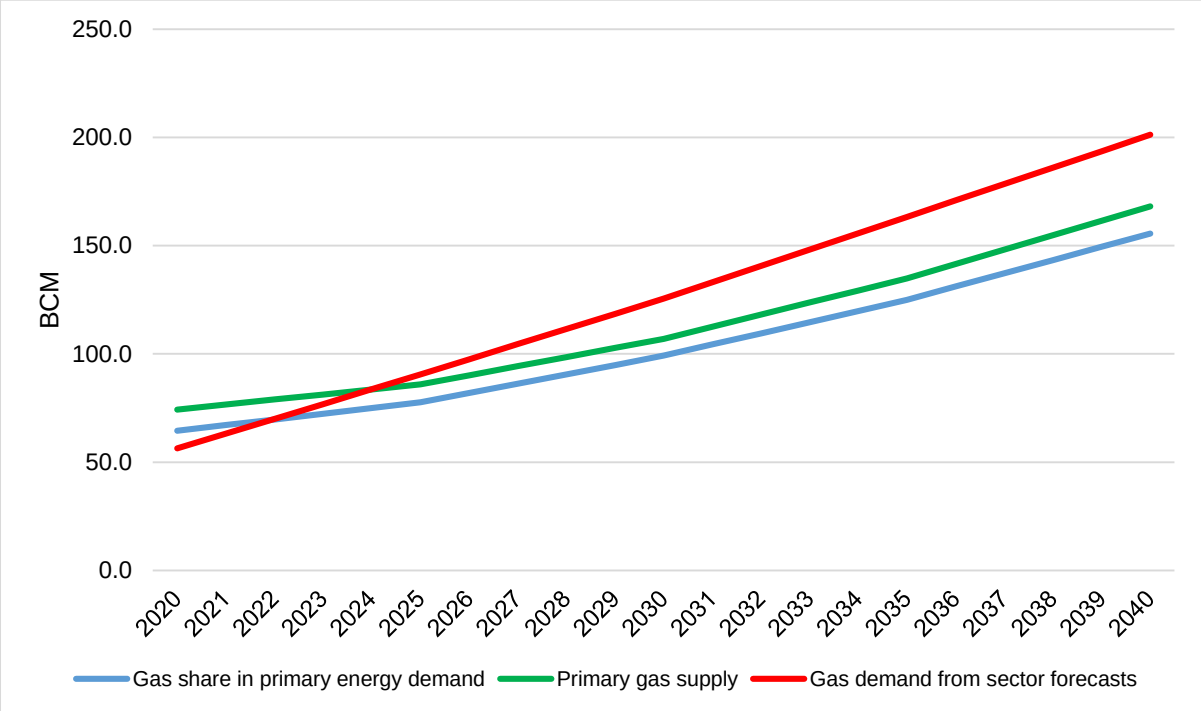
By contrast, in the transportation sector, gas is absent, with demand being met by oil and biofuels. In the household sector, the share of electricity in domestic demand rises from 60 per cent in 2018 to 90 per cent in 2050, with the remainder largely met through LPG that continues to be consumed at current volumes. Therefore, household gas demand is forecast to reach just 2.2 mtoe (2.3 bcm) in 2050, and less than half of that by 2040.[97] It is a similarly story in the commercial sector, in which electricity meets 60-70 per cent of final demand, with the remainder being largely met by LPG. Even by 2040, gas demand in this sector is less than 1 mtoe (less than 1 bcm).[98] Gas is also entirely absent from the 'other sectors' classification. Therefore, between the transportation, household, commercial, and 'other' sectors, total gas demand is forecast at around 3 bcm by 2040, from zero today.

To recap, we are left in the unfortunate position where we have three forecasts for Indonesian gas demand from the same NEC Outlook document. Firstly, gas demand based on the share of gas in forecast primary energy demand is forecast at 64.5 bcm in 2020, 77.6 bcm in 2025, 99.2 bcm in 2030, 125.0 bcm in 2035, and 155.6 bcm in 2040.[99] Secondly, primary gas supply (presented in mtoe in the *Outlook* appendix and converted to bcm) is forecast at 74.3 bcm (2020), 85.9 bcm (2025), 107.0 bcm

[94] NEC, 2019. Outlook. p.45-47
[95] NEC, 2019. Outlook. p.8-9
[96] NEC, 2019. Outlook. p.48
[97] NEC, 2019. Outlook. p.28
[98] NEC, 2019. Outlook. p.29
[99] NEC, 2019. Outlook. p.36

(2030), 134.9 bcm (2035), and 168.2 bcm (2040).[100] Finally, gas demand for industry and power generation alone based on the sector forecasts discussed above is forecast at 44.0 bcm (2020), 76.2 bcm (2025), 108.3 bcm (2030), 143.6 bcm (2035), and 178.9 bcm (2040). To this must be added energy sector own use and losses (set at 9.5 per cent of gas production – the ratio in 2018) and non-energy use (set to grow at 5 per cent per year, in line with the Outlook forecast for Indonesian GDP growth). This brings the third forecast ('Gas demand from sector forecasts') up to 56.3 bcm (2020), 90.5 bcm (2025), 125.5 bcm (2030), 163.3 bcm (2035), and 201.2 bcm (2040).

**Figure 18: Indonesian gas demand forecasts from the NEC Outlook to 2040**




Source: Data from NEC Outlook

The first forecast ('Gas in primary energy demand') and second forecast ('Primary gas supply') refer to domestic consumption including LNG and pipeline gas exports. The third forecast refers to domestic gas consumption but excludes the use of gas for pipeline and LNG exports. These forecasts are illustrated in Figure 18.

By contrast, APEC offers a more modest outlook, which forecasts total Indonesian gas demand to grow from 45 bcm in 2016 to around 74 bcm in 2040 – the point at which it surpasses domestic production – and onward to 100 bcm in 2050. Within that, industrial gas demand grows from 9.5 bcm in 2016 to 26 bcm in 2050, while the combined consumption of gas for power generation and in the gas sector itself rises 3.5 times, from 28 to 70 bcm. Combined gas demand from buildings and transport rises from 1 bcm in 2016 to 8 bcm in 2050.[101] The APEC Outlook therefore forecasts gas demand for industry and power generation in 2040 at levels half those forecast by the NEC.

The IEA *World Energy Outlook 2017* (New Policies Scenario) forecasts gas demand to rise more quickly than in the APEC Outlook, but more modestly than the Indonesian Energy Ministry: Total gas demand is forecast to rise from 44 bcm in 2016 to 56 bcm (2025), 69 bcm (2030), 88 bcm (2035), and 118 bcm (2040). These IEA figures include gas demand for power generation, consumption in the industrial, residential, commercial, and transport sectors, energy sector use (including losses), and non-energy

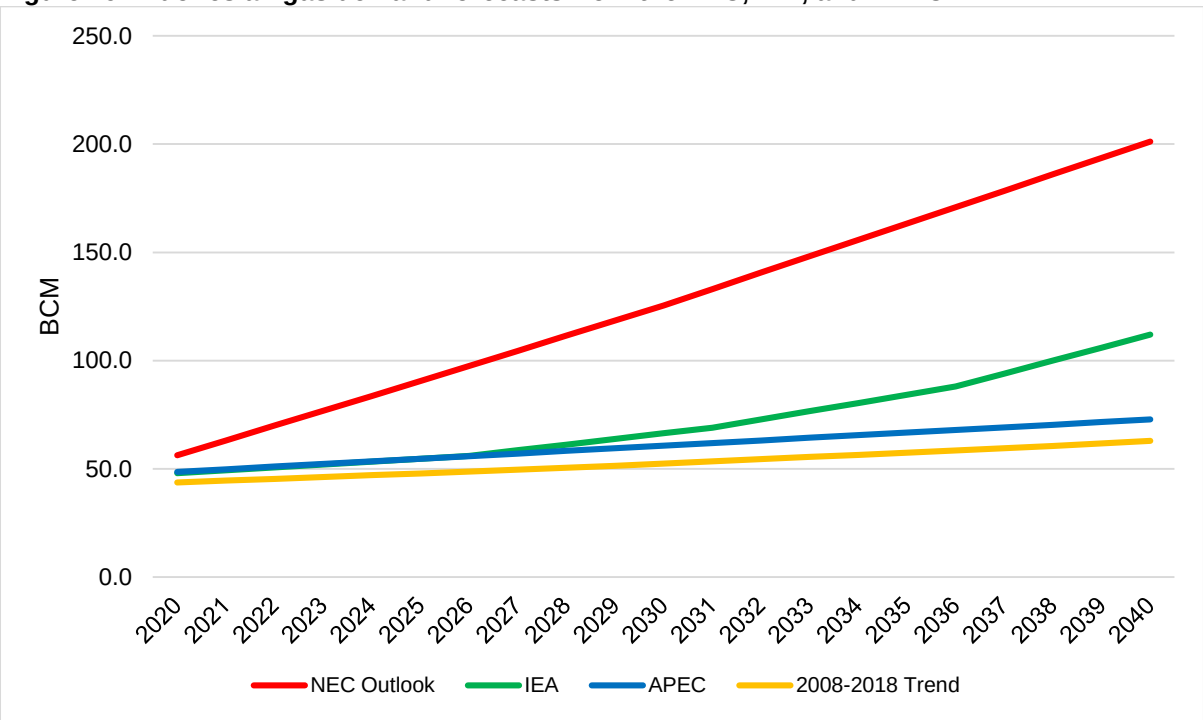
[100] NEC, 2019. Outlook. p.73
[101] APEC Energy Working Group, 2019. *APEC Energy Demand and Supply Outlook. 7th Edition – Vol. II*. https://www.apec.org/Publications/2019/05/APEC-Energy-Demand-and-Supply-Outlook-7th-Edition---Volume-II. p 131

use. This does not include LNG or pipeline exports. The APEC and IEA forecasts are similar insofar as they both foresee Indonesian electricity demand tripling by 2040 – a more modest forecast than the NEC Outlook, which forecasts Indonesian electricity demand to grow 5.6 times by 2040.

It should also be noted that the IEA and APEC forecasts begin from 2016 as their most recent data, and thus their figures for 2018 are projections that are higher than the actual gas demand reported by the NEC, which takes 2018 as its most recent data.

Finally, in the decade between 2008 and 2018, domestic Indonesian gas consumption (excluding exports and non-energy gas consumption) rose by 20 per cent. If that growth rate is projected forwards, Indonesian gas demand will rise from its current level of around 42 bcm in 2018 to 52 bcm in 2030 and 63 bcm in 2040.

**Figure 19: Indonesian gas demand forecasts from the NEC, IEA, and APEC**



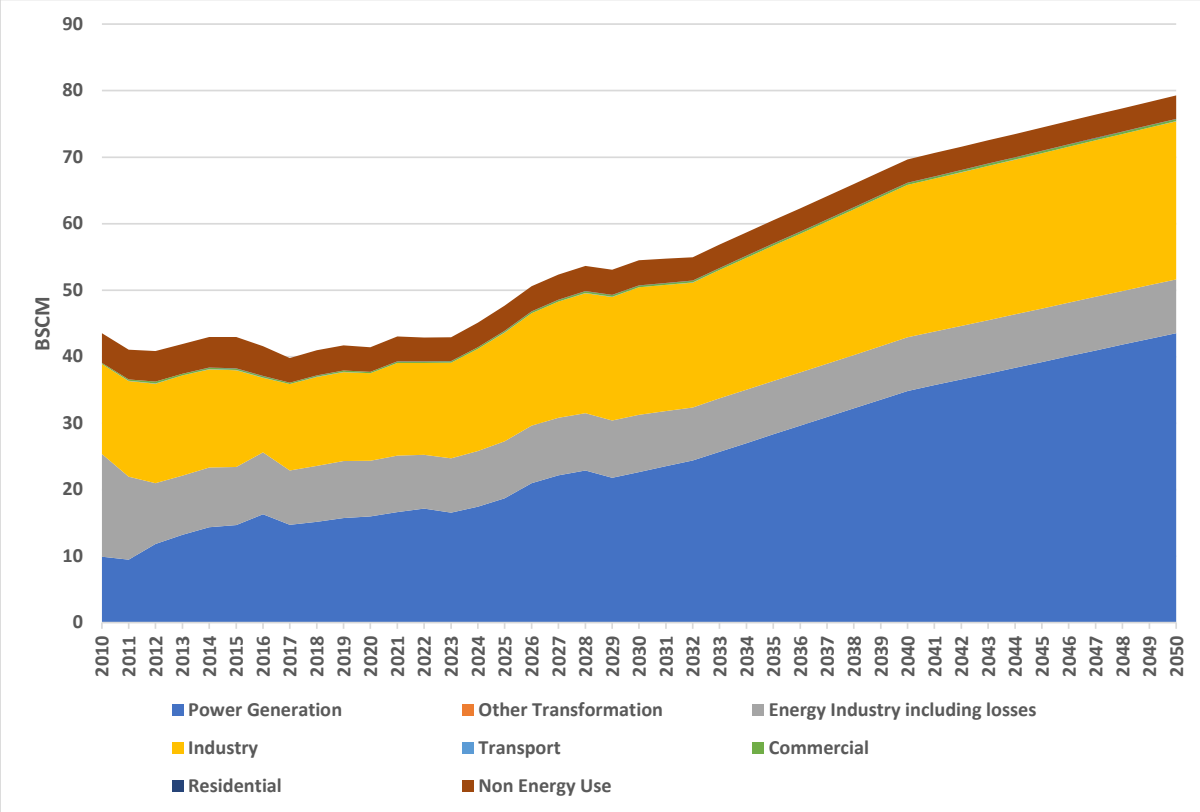

Source: NEC Outlook, IEA WEO 2017, APEC Outlook

The NEC forecast for gas demand based on the sectoral demand discussed earlier (i.e. the third NEC forecast from the trio above) is plotted on Figure 19, along with the IEA and APEC forecasts, and a line indicating the simple continuation of the demand growth experienced in 2008-2018.

The consensus of the forecasts examined above is that Indonesian gas demand will indeed rise, but the forecasts vary dramatically in their forecasts of the rate of that growth. The trends of the past decade certainly render the Energy Ministry Outlook bullish, and even the IEA forecast is optimistic, while the APEC forecast is closer to current trends. As a reminder, the IEA forecast was published in 2017, while the APEC forecast was published in 2019, so it is not surprising that the latter is closer to current trends.

The forecast generated by the research conducted for this paper does not replicate the bullish growth foreseen by the Indonesian Energy Ministry. Rather, it shares the predictions of relatively modest growth in the first half of the 2020s offered by the IEA and APEC. Growth in gas demand is forecast to accelerate from the late 2020s onwards, with the result that by 2040, Indonesian gas demand will be somewhere between the levels forecast by the IEA and APEC. The main driver of growth will be gas-fired power generation, supported by secondary growth in industrial sector gas demand.

**Figure 20: Forecast Indonesian Gas Demand by Sector**




Source: Data from IEA, OIES

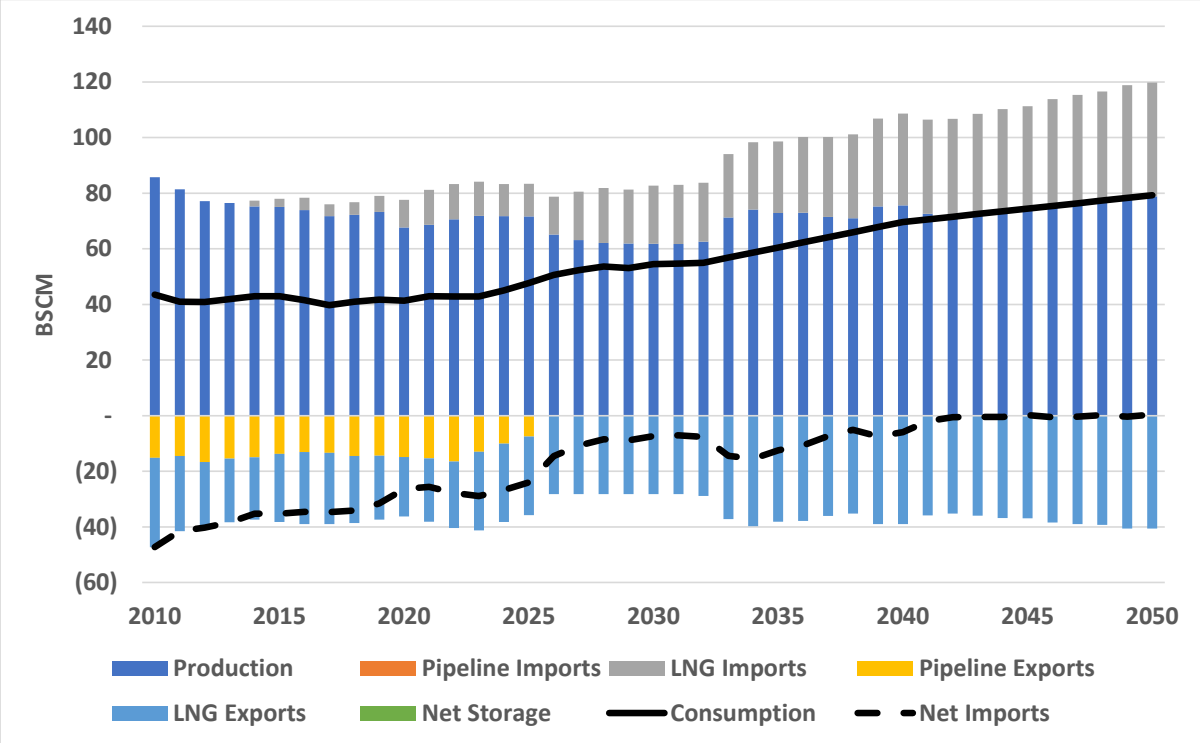
### *From gas exporter to gas importer*

The future balance between domestic production and demand in Indonesia will determine Indonesia's status as a gas-exporting country. In the first half of the 2020s, Indonesian gas demand is forecast to grow gradually, while gas production is set to remain stable. From the mid-2020s onwards, the accelerating growth in Indonesian gas demand (especially for power generation) is set to outpace the growth in Indonesian gas production, which will be supported by the launch of several new production projects that have either recently taken FID or are set to do so in the next 1-2 years. By the 2030s, if major new offshore or non-conventional gas production projects are not launched, Indonesian gas production is forecast to enter a period of gradual decline. With growth in domestic demand continuing, Indonesia could become a net gas importer around 2040.

The more bullish forecast for domestic Indonesian gas demand offered by the Indonesian Energy Ministry means that the Ministry expects Indonesia to become a net importer before 2040. Speaking at the Gas Indonesia Summit in July 2019, the Indonesian Energy Minister, Ignasius Jonan, told the audience that Indonesia expects to increase the share of gas in the primary energy mix (mostly for power generation and industrial consumption). To achieve this, Indonesian LNG supplies will increasingly be directed to the domestic market, with LNG exports potentially falling by 20 per cent by 2025 and possibly halting altogether by 2036.[102] This is a view shared by the IEA, which foresees Indonesia becoming a net importer by the mid-2030s, while APEC forecasts Indonesia to become a net gas importer around 2040.[103] [104]

[102] Argus Direct, 2019. Indonesia targets 2036 halt to LNG exports. *Argus Direct*, 14 August.
[103] IEA, 2017. *World Energy Outlook 2017 Special Report: South-East Asia Energy Outlook*. p.83
[104] APEC, 2019. p.138, 144

**Figure 21: Indonesian forecast future gas balance**




Source: IEA, OIES Estimates, Nexant World Gas Model

The direction of Indonesian LNG supplies to the domestic market is highlighted in the graph above: The 'LNG imports' through to 2040 are, in fact, supplies from Indonesian liquefaction plants being regasified in other areas of the country. Likewise, the 'LNG exports' includes supplies delivered to the domestic market. It is the increasing supply of LNG to the domestic market that causes the 'Net LNG Exports' in the graph to decline to around zero by 2040.

The potential winding down of Indonesian gas exports may be judged by the status of Indonesian gas export contracts. Pertamina's contracts to supply gas to Malaysia by pipeline will expire in 2021, while the pipeline export contracts for supplies to Singapore will expire in 2022/2023. Meanwhile, of a total of 16.56 mtpa of LNG export contracts currently in force, 6.66 mtpa of contracts (3.1 mtpa of domestic market contracts and 3.56 mtpa of export contracts) will expire in 2020-2025. This will be followed by the expiry of 7.3 mtpa of export contracts in 2025-2030, and the expiry of 3.6 mtpa of export contracts in 2030-2035. If these contracts are not renewed as they expire, this will be a significant indicator that Indonesia is transitioning towards supplying its LNG primarily to its own domestic market.

In this context, it should be remembered that the difference between LNG export prices and Indonesian domestic gas prices will remain a key factor in the future development of the sector. To ensure gas supply to power generators in Indonesia, the government began regulating gas supply allocation and prices of natural gas for domestic power generators in 2017. These regulations set a maximum price for domestically produced gas and clarify the conditions for power generators to procure indigenous gas or imported liquefied natural gas (LNG).[105] As noted earlier, producers of gas in Indonesia are obliged to market 25 per cent of their production on the domestic Indonesian market, as their Domestic Market Obligation (DMO).

The capping of domestic prices will encourage growth in domestic gas demand, but it also means that foreign companies investing in Indonesian gas extraction and LNG production will continue to seek more lucrative LNG exports beyond their DMO. If it were unwilling to raise domestic prices, the only

[105] IEA, 2017. p. 59

way for the Indonesian government to prevent this leading to a shortage on the domestic market would be by enforcing a greater role for state-owned Indonesian companies, such as Pertamina, in gas extraction and LNG projects.

At present, the realisation of projects via PSCs – and the increasing role played by Indonesian state-owned companies in those projects – suggest that the Indonesian government is coming down on the side of prioritising domestic supply. Given the difficulties faced by Pertamina in meeting its production targets and the investment needed to maintain production levels, this approach could curtail the long-term growth in Indonesian gas production, or at least hinder the development of new projects in the 2030s. If the need to support investment in production through more profitable domestic sales subsequently necessitates domestic gas price increases, these higher prices could in turn curtail some of the growth forecast by the Indonesian government.

## Conclusions

For the purpose of this collected volume, while other chapters focus on the potential for LNG import demand, this chapter has focussed on the prospects for Indonesia as a regional LNG supplier to the Asia-Pacific market as well as its potential future gas market. The main conclusion to draw is that Indonesia's role as a regional LNG supplier is set to diminish in the coming 20 years, which could eventually see the country become a net importer.

Having been a world-leading supplier of LNG to the global market for several decades, Indonesia found itself in a period of stability from 2002 to 2014, with gas production (75-80 bcma), domestic demand (35-40 bcma), and exports (35-40 bcma) all showing relatively flat growth. However, since 2014, the first signs of a transition period have become apparent, as initially small volumes of LNG from Indonesian export terminals are being directed to Indonesian import terminals, rather than the international market. Over the coming decade, domestic consumption is likely to rise on the basis of demand from the power generation and industrial sectors, diverting supplies from LNG and pipeline exports, as the relevant contracts expire. This trend could become more pronounced during the 2030s, as the remaining export contracts expire and domestic gas demand rises further, with government policy prioritising the supply to the domestic market.

The main drivers of growth will be the rising population, increasing per-capita electricity consumption, and growth in industrial activity as part of Indonesia's overall economic growth. These three indicators will be signposts for growth in total power generation and industrial-sector energy demand. Given the share of gas in power generation is forecast to remain at around 25-30 per cent and the share of gas in industrial energy demand is forecast to remain at around 35-40 per cent, the absolute levels of energy demand for power generation and industrial activity will be the major determinants of Indonesia's future gas demand.

To meet this growing demand, Indonesia will rely on the ramping up of new gas production projects during the 2020s. It also appears likely that a growing proportion of Indonesian LNG production will be directed to the domestic market. The key signposts here will be the scaling down of pipeline exports, the non-renewal of LNG export contracts, and the further deployment of FSRUs, such as the three launched between 2012 and 2016. Further growth in gas production – or, indeed, even the maintenance of current production levels – in the mid-2030s would require the development of large, new, offshore projects (such as the challenging East Natuna) and/or the development of non-conventional production (such as coalbed methane).

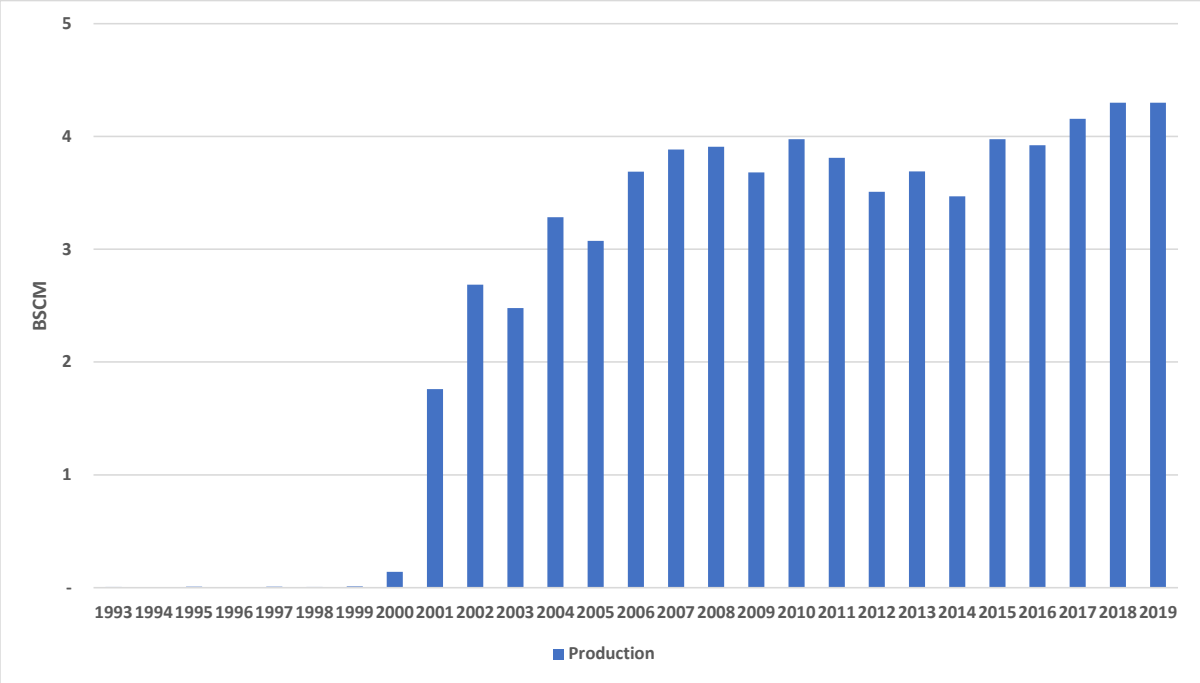
Overall, the current trends and forecasts suggest that Indonesian gas demand is likely to grow faster than production over the coming two decades, with the result that Indonesia will eventually move from being a net gas exporter supplying the Asia-Pacific market to being a net gas importer, potentially competing for supplies on that market. This transition is likely to be gradual, with the 'tipping point' occurring around 2040, with significant implications for the Asia-Pacific regional LNG market.

## PHILIPPINES

### Historic Supply Demand and Infrastructure

Apart from very small-scale gas supply to a 3MW power plant from the onshore San Antonio field, the gas industry in the Philippines started with production from the Malampaya field, offshore the island of Palawan, in 2001. Prior to 2001, total natural gas production in the Philippines totalled less than 0.01 Bcm per year.

**Figure 22: Philippines Natural Gas Production 1994-2019[106]**



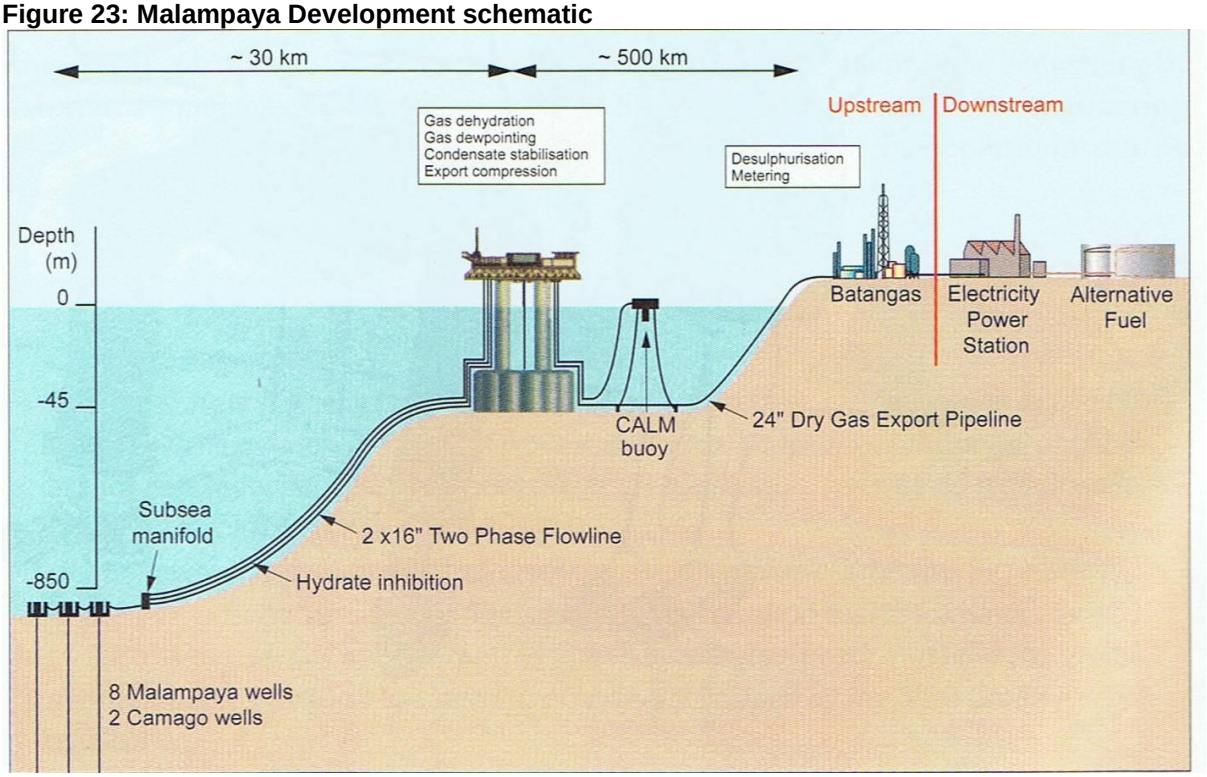

Source: IEA

By 2005, total production, nearly all from the single Malampaya development, had ramped up to around 3 Bcm per year and has remained between 3 and 4 Bcm since then.[107]

As shown in Figure 233[108], and the map in Figure 24, Malampaya is a deepwater development, linked to a shallow water platform for initial gas processing, with a 500 km subsea pipeline linking the platform to the landfall in Batangas, a city on the main island of Luzon about 100km south of the capital, Manila.

[106] IEA data
[107] Philippines Department of Energy: https://www.doe.gov.ph/natgas/natural-gas-production-consumption-february-7-2019
[108] https://www.tallrite.com/images/SPEX/MalampayaSchematic.jpg

**Figure 23: Malampaya Development schematic**




Source: https://www.tallrite.com/

After further processing in the onshore gas plant, the gas was initially contracted to be supplied to 3 CCGT power plants: the 1200MW Ilijan power plant developed by the (then) state-owned National Power Corporation and two power plants (now known as Santa Rita (1000MW) and San Lorenzo (500MW)) located at Santa Rita, developed by a consortium led by First Philippine Holdings. In 2016, in the expectation of future LNG imports, First Philippines added two further power plants at the same site, a 414MW CCGT, San Gabriel, and a 97MW open cycle gas turbine, Avion.[109] All power plants are within less than 20km of the landfall. While there has been consideration of building a gas pipeline from Batangas to Manila ("BatMan pipeline") and various other potential pipeline projects, no further natural gas pipeline infrastructure has been constructed to take Malampaya gas further downstream. More than 97 per cent of all gas production is consumed in the power sector, with the balance being supplied as feedstock to the Shell refinery in Batangas.[110] Between 2008 and 2014 a small amount of gas was used for a pilot scheme to supply CNG to buses operating between Batangas and Manila, but this has been discontinued.[111]

(For completeness, the small Libertad gas field on the island of Cebu started production in 2012, supplying a 1MW power plant for a period of five years. It appears that this project was not commercial, no additional reserves were found and it is in the process of being abandoned.[112]).

As can be seen from

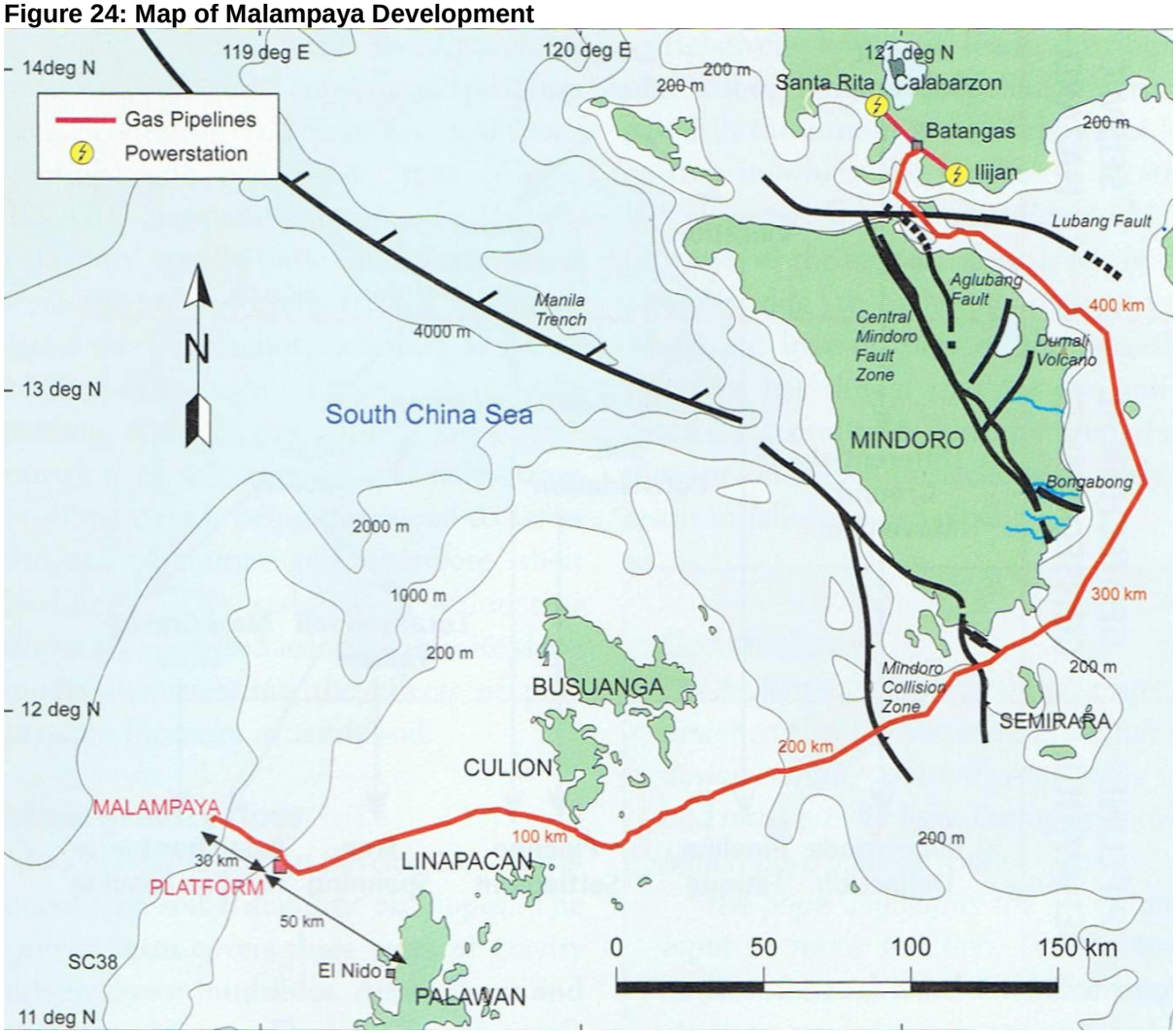
Source: https://www.tallrite.com/

[109] https://www.firstgen.com.ph/our-business/our-power-plants/
[110] https://www.doe.gov.ph/natgas/natural-gas-production-consumption-february-7-2019
[111] https://pnoc-ec.com.ph/compressed-natural-gas-project/ PAGE NOT FOUND
[112] https://businessmirror.com.ph/2019/02/18/phl-natural-gas-output-peaked-in-2018/

Figure 25[113], natural gas fired power generation has been largely flat since Malampaya reached plateau production in 2005, while coal has significantly increased its share of power generation since 2008.

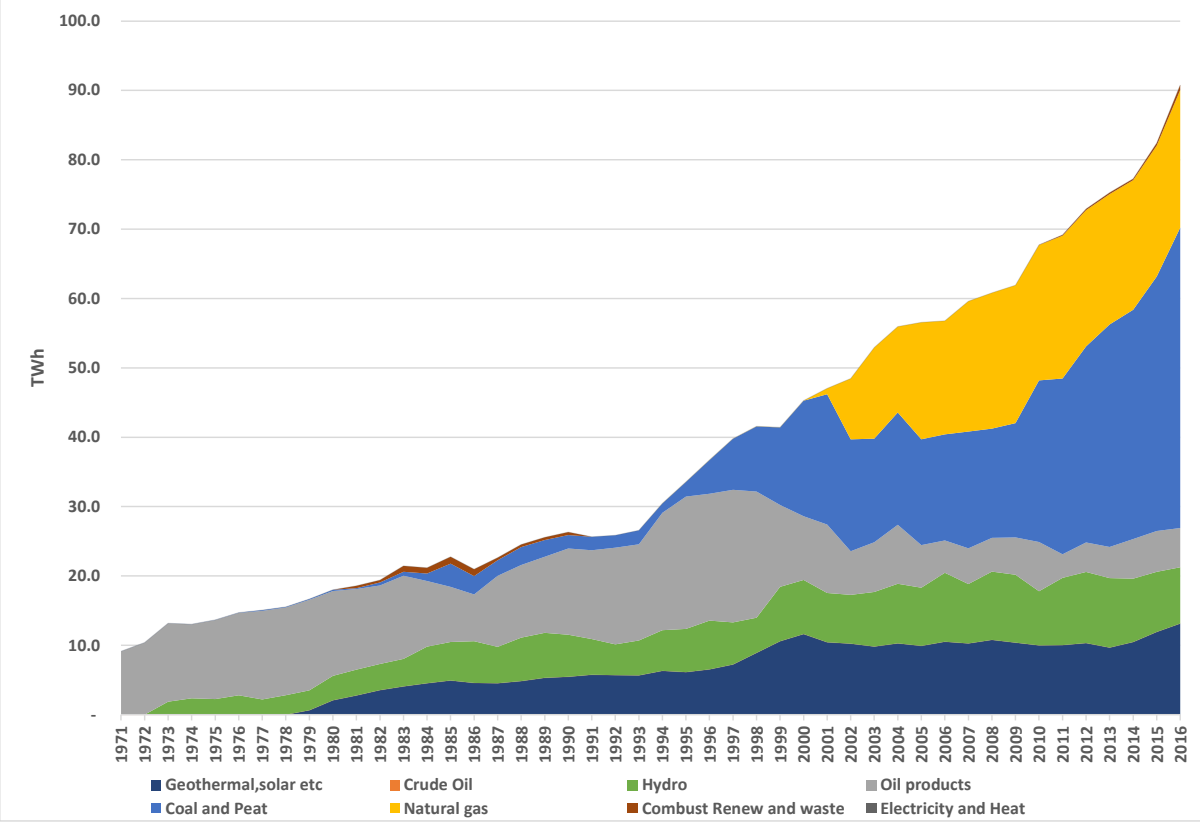
[113] https://www.adb.org/sites/default/files/publication/463306/philippines-energy-assessment-strategy-road-map.pdf page 13.

**Figure 24: Map of Malampaya Development**




Source: https://www.tallrite.com/

**Figure 25: Philippines Power generation by source 1990-2016**




Source: IEA

## Government Policy and Regulation

The Philippines Department of Energy (DoE) is the key body responsible for co-ordination of government policy and activities in the energy sector.[114] DoE produces the Philippine Energy Plan, the most recent edition of which covers the period from 2017-2040. At a high level, the stated policy objective is to "improve the quality of life of the Filipino by formulating and implementing policies and programs to ensure sustainable, stable, secure, sufficient and accessible energy".[115]

With nearly all the natural gas in the Philippines being used in the power generation sector, regulation of the electricity sector is a key consideration for further development of the natural gas industry. In 2001, the Philippine Congress passed the Electric Power Industry Reform Act (EPIRA)[116] in order to:

I. restructure the Philippine electric industry into four major sectors – generation, transmission, distribution and supply;

II. privatise several state-owned assets, which paved the way for the entry of private investors;

III. enable the creation of the wholesale electricity spot market; and

IV. enable the introduction of open access and retail competition.

The process of implementing the EPIRA and privatisation of assets has been taking place gradually since 2001.

[114] https://www.doe.gov.ph/pep
[115] Energy Annual Report 2018, p2
[116] https://thelawreviews.co.uk/edition/the-energy-regulation-and-markets-review-edition-7/1171268/philippines

In addition, the Renewable Energy Act (2008) and the Philippine Green Jobs Act (2016) introduced a feed-in-tariff system and other incentives for renewable energy developers.

The investment in the Malampaya development (committed in 1998, before the EPIRA) was underpinned by Take or Pay (ToP) contracts which guaranteed the revenue stream to the gas field and power plant developers.[117] As a result of these ToP contracts, the power plants have consistently run at base load (operating >70 per cent of the time) up to the ToP level, since the marginal cost of gas up to that level is effectively zero.[118] These costs are ultimately passed through to the end customers of the Manila Electric Company, Meralco, which was the monopoly power distributor to the greater Manila area.

The EPIRA introduced the Wholesale Electric Spot Market (WESM), under which power plants are dispatched on the basis of short run marginal cost. As a further step, Retail Competition and Open Access is being introduced, taking away the Meralco monopoly.[119] In theory at least, a large distribution utility, like Meralco, could enter into a power purchase agreement (PPA), to provide greater certainty to the power plant / gas infrastructure developer. However, such a PPA would need to be approved by the Energy Regulatory Commission (ERC). In 2015, DoE issued a circular requiring all distribution utilities to carry out a Competitive Selection process before seeking approval of a PPA from the ERC.[120] All of these steps have made it much more difficult for project developers to have sufficient confidence in the future revenue stream to underpin potential new infrastructure investments (both new power plants and gas / LNG infrastructure). Where power projects have progressed, the regulatory structure has tended to favour coal plants which are evaluated as having a lower cost of generation than natural gas fired power plants (see Supply / Demand Projection below).

A draft natural gas master plan was produced in 2013/14 with support from the World Bank and Australian Aid[121], but this did not result in any clear policy support for further natural gas / LNG developments. In 2017, the Department of Energy issued a circular covering certain rules and regulations, mainly related to permitting of downstream natural gas developments.[122] However, there is not yet a clear government policy or regulatory structure to promote further development of the natural gas sector.

## Supply / Demand Projection

With the existing gas fired power generation of a little over 3,000MW in the Batangas area, a robust business case for potential new gas or LNG developments is likely to rely on supplying those power plants as production available from Malampaya decreases. There could also be potential to supply additional gas fired power generation and limited industrial or transport demand on the main island of Luzon. Luzon's current peak power demand of around 10,000 MW, is forecast to grow to around 30,000 MW by 2040.[123] The government does not have a target fuel mix policy, and, as noted above, the regulatory framework has tended to favour coal-fired generation. The DoE list of committed power plants for Luzon as at April 2019[124], showed 3,950MW of coal fired generation out of a total of 4,835MW. The corresponding list of "indicative" plants[125] (of projects being considered by potential developers, many of which will not actually come to fruition) has 8,935MW coal, 6,160MW natural gas and 14,821MW renewables. As in many Asian markets, natural gas-fired power generation is clearly at risk of losing out to environmentally acceptable renewables or lower cost coal.

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[117] https://www.doe.gov.ph/sites/default/files/pdf/downstream_natgas/malampaya_history.pdf
[118] https://lantaugroup.com/files/ppt_pgen14_sf.pdf slide 3.
[119] http://documents.worldbank.org/curated/en/428331548771494859/pdf/WPS8721.pdf
[120] https://www.doe.gov.ph/sites/default/files/pdf/issuances/dc_2015-06-0008.pdf
[121] https://www.doe.gov.ph/sites/default/files/pdf/downstream_natgas/wb_phase2.pdf
[122] https://www.doe.gov.ph/sites/default/files/pdf/issuances/dc2017-11-0012.pdf
[123] Power Development Plan 2016-2040, page 45
[124] https://www.doe.gov.ph/sites/default/files/pdf/electric_power/luzon_committed_april_2019.pdf
[125] https://www.doe.gov.ph/sites/default/files/pdf/electric_power/luzon_indicative_april_2019.pdf

As noted above, gas supply from Malampaya has been at a plateau level in the range 3.5 to 4 bcm per year (consistent with supplying around 3,000MW of power generation at base load) since 2005. While end of field life production is somewhat uncertain, according to DoE and the operator, Shell, production is expected to decline from around 2022.[126] The current production licence expires in 2024, but, subject to agreeing an extension, some production is expected to continue until around 2027 to 2029.

While some exploration has been taking place for further gas fields, there is not yet any prospect of further domestic gas production, so any use of gas beyond the end of Malampaya production is likely to require imports of LNG, at least in the short term. If a significant new field were to be discovered, it would most likely take several years to be developed, unless it was located very close to the existing Malampaya infrastructure.

### Potential Gas / LNG Import Infrastructure

From as early as 2003,[127] various project developers have proposed LNG import terminal projects in the Philippines. One project, Energy World's LNG hub project in Pagbilao, about 150 km SE of Manila and about 90km E of Batangas, has been under construction for some time, but has been subject to rolling delays. The Australian registered Energy World Corporation has recorded its intended progress in a series of announcements to the Australian stock exchange.[128] In 2009, the Philippine import project was "scheduled to commence operation in 2011", but it has been repeatedly pushed back giving little confidence, ten years later, that it will actually be completed.

Currently, in addition to Energy World, two other LNG projects are still trying to progress.

First Philippine Holdings, the company behind over 2,000MW of the current gas-fired power generation, through its subsidiary First Gen, has been trying for several years to develop and finance an LNG import project. First Gen has a preference for an onshore terminal to avoid the risk of supply interruptions related to operating an FSRU in a typhoon-prone area. The LNG receiving terminal would be located adjacent to the existing power plants. In May 2019, having partnered with Tokyo Gas, a "ground breaking" ceremony was held,[129] even though it was made clear that the project had not yet taken its final investment decision, which was targeted in 2020. It appears that a significant hurdle still to be overcome is to secure a long-term power purchase agreement for the offtake of power, which could also underpin financing for the LNG import terminal. First Gen and Meralco have been discussing such a long-term PPA for some years but have not yet reached an agreement. If agreement were to be reached, it would still be subject to approval by the ERC. In September 2019, First Gen announced that it had appointed the Japanese company, JGC, as its EPC contractor.[130] Perhaps more significantly, they also announced an intention to convert the existing liquid fuel jetty to be suitable for a FSRU, which may enable an earlier start to LNG imports and prove easier to finance than an onshore terminal.

In parallel, a separate project in Batangas, Tanglawan LNG, was being pursued by a local fuel retailer, Phoenix Petroleum, in cooperation with the Chinese National Offshore Oil Company (CNOOC), and, more recently the Philippine National Oil Company (PNOC) joined as a partner.[131] The stated capacity of this project is 2.2 mtpa of LNG, and it appears to be linked to the construction of 2,000MW of new power generation capacity, rather than supplying the existing gas-fired power plants. Limited details have been disclosed regarding the project, and it remains unclear how the commercial and financing arrangements for the project would be structured. In December 2019, it was reported that the project had been "shelved for the time being"[132], and it remains unclear when or if it may restart.

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[126] https://www.erce.energy/news/time-step-gas-philippines-lng-september-2018
[127] https://www.philstar.com/business/2003/11/25/229194/pnoc-firms-lng-proj-gnpower
[128] https://www.smh.com.au/business/jamaicans-question-deal-with-australian-company-20131010-2va5l.html
[129] https://www.philstar.com/business/2019/05/29/1921641/first-gen-breaks-ground-batangas-lng-terminal
[130] https://www.bworldonline.com/first-gen-picks-japanese-firm-as-epc-contractor-for-lng-terminal/
[131] https://www.philstar.com/business/2019/03/12/1900581/tanglawan-targets-start-lng-hub-construction-may
[132] https://www.kallanishenergy.com/2019/12/19/philippines-2b-tanglawan-lng-project-shelved/

It has also been reported that a consortium of LT Group and JG Summit are considering an FSRU in Batangas Bay, probably adjacent to the JG Summit chemical plant in Pinamucan.[133] This project appears to be at an early stage, and has not yet obtained formal endorsement from the Department of Energy.

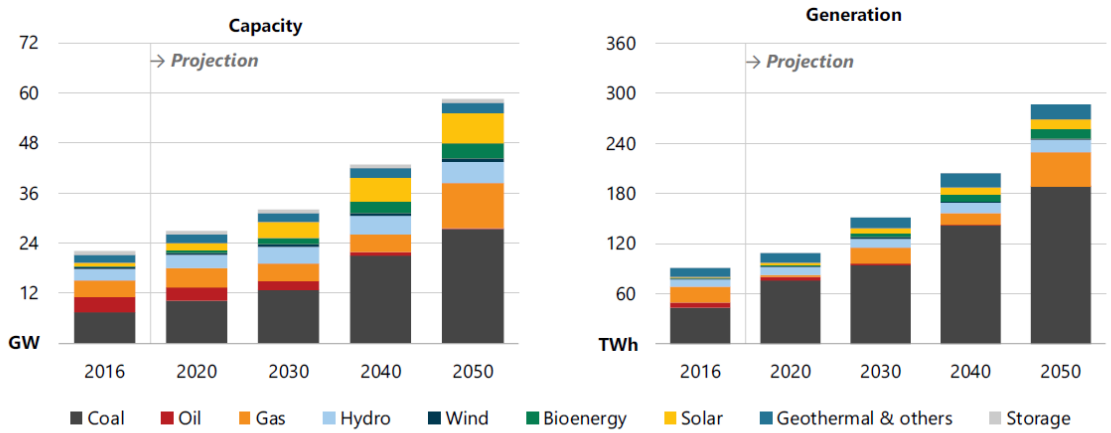
Finally, Excelerate Energy has also joined the group of project proponents looking to develop an LNG import project to the Philippines.[134] This appears to be linked to the Ilijan power plant, but further details of the project have yet to be released.

For completeness, it should also be mentioned that the Philippines had at one time been considered as part of the Trans-ASEAN gas pipeline (TAGP). A TAGP Task Force had been formed in 1999, and a formal Memorandum of Understanding signed in 2002.[135] It envisaged a possible link from Sabah, Malaysia to the Philippines, perhaps by utilising spare capacity in the Malampaya pipeline. However, there has been little further progress on these plans, and given the size and flexibility of demand in the Philippines, LNG imports appear to be more realistic, although, as noted above, still challenging.

## Future Gas Demand Scenarios

The 7th APEC Energy Outlook[136], published in May 2019 contemplates two significantly different scenarios for future Philippines power demand and supply. In Business as Usual, coal generation, continues to grow rapidly, as illustrated in Figure 26.

**Figure 26: APEC power generation projections: business as usual**



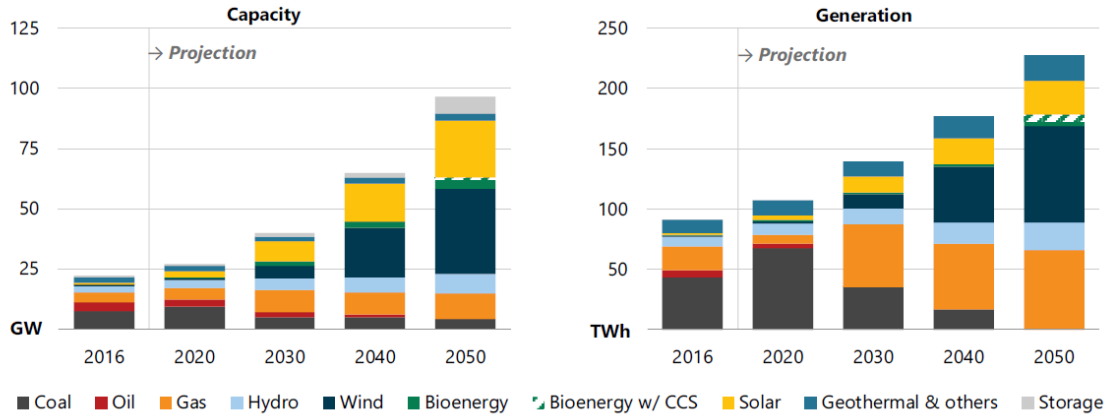

Sources: APERC analysis and IEA (2018a).

By contrast, in the APEC Low Carbon scenario, coal-fired generation capacity decreases rapidly from 2020 onwards and is largely replaced by wind and solar capacity, as illustrated in

[133] https://www.bworldonline.com/lng-storage-backers-tout-lucio-tan-jg-summit-companies-as-gas-users/
[134] https://excelerateenergy.com/excelerate-receives-notice-to-proceed-from-the-philippines-for-floating-lng-terminal/
[135] https://asean.org/?static_post=the-asean-memorandum-of-understanding-mou-on-the-trans-asean-gas-pipeline-tagp
[136] https://www.apec.org/Publications/2019/05/APEC-Energy-Demand-and-Supply-Outlook-7th-Edition---Volume-I

Figure 27.

**Figure 27: APEC power generation projection, Low Carbon scenario**




Note: CCS = carbon capture and storage.
Sources: APERC analysis and IEA (2018a).

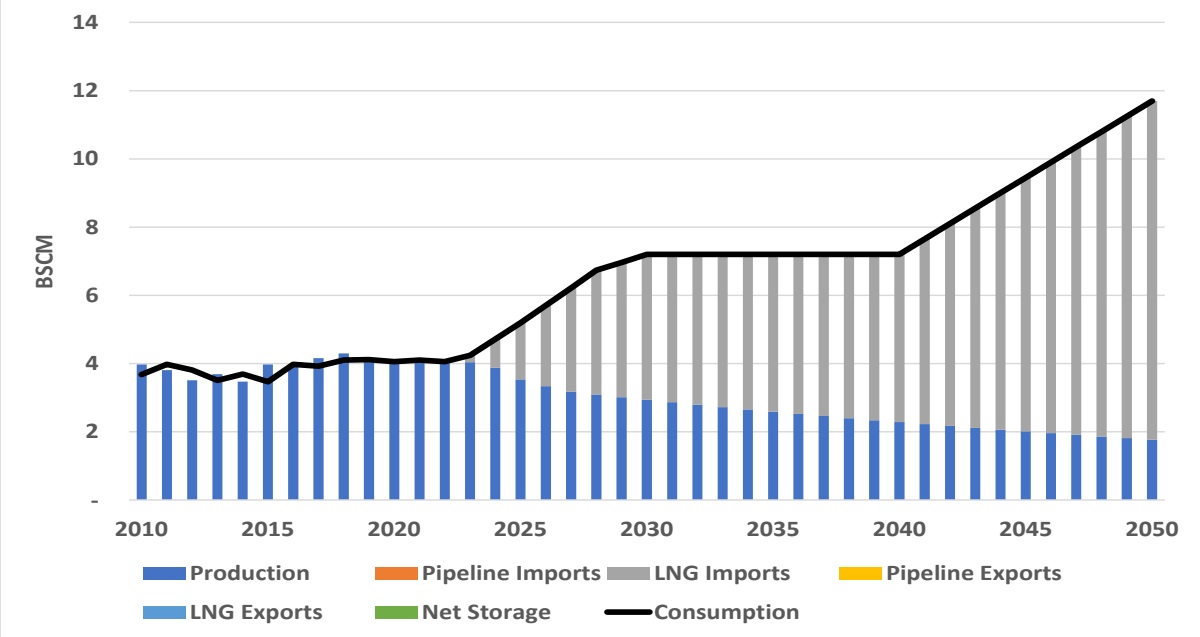
The total capacity of gas-fired power generation does not grow rapidly in either scenario, with little change in Business as Usual and growth from the current 3 GW to nearly 10GW by 2030 in the Low Carbon scenario. The APEC projections also seem to show a very high utilisation of the gas-fired generation in the Low Carbon scenario – which is somewhat hard to reconcile with the large share of intermittent renewable generation.

## Conclusions

Against the background described above, we see two potential paths forward for gas and LNG in the Philippines. There is clearly a possibility that in the absence of clear government policy support, it will not prove possible for private investors and financiers to justify an investment in an LNG import terminal. In this scenario, as Malampaya depletes and the existing contractual arrangements come to an end between 2022 and 2024, the existing gas-fired power plants will move from their current base load to peaking operation. Malampaya will continue to supply those plants for a few years until the end of field life, at which points the plants will either be decommissioned or run occasionally on liquid fuel.

In a success case for LNG, at least one LNG import project will be completed. If the First Gen project is able to secure creditworthy power offtake arrangements, it would seem to have a reasonable chance of success, given its control of 2,000MW of power generation capacity. With the current structure of the power market, and the likely completion of significant coal and renewables capacity, the gas-fired power plants would most likely operate at a much lower load factor than has been the case under the current take or pay arrangements. Thus, the 3,000MW of power generation would be likely to require between 1 and 2 mtpa of LNG. Once an LNG receiving terminal is in operation, it is reasonably likely that additional gas demand, mainly for power generation, but also potentially for industrial or transport uses will emerge. It is reasonable to assume that 1,000 to 2,000MW of additional gas-fired power generation capacity may be constructed. Even in this success case, it is difficult to see that LNG demand in the Philippines would be higher than 5 mtpa by 2035.

**Figure 28: Philippines Projected Supply – Demand Balance**




Source: IEA, OIES Estimates, Nexant World Gas Model

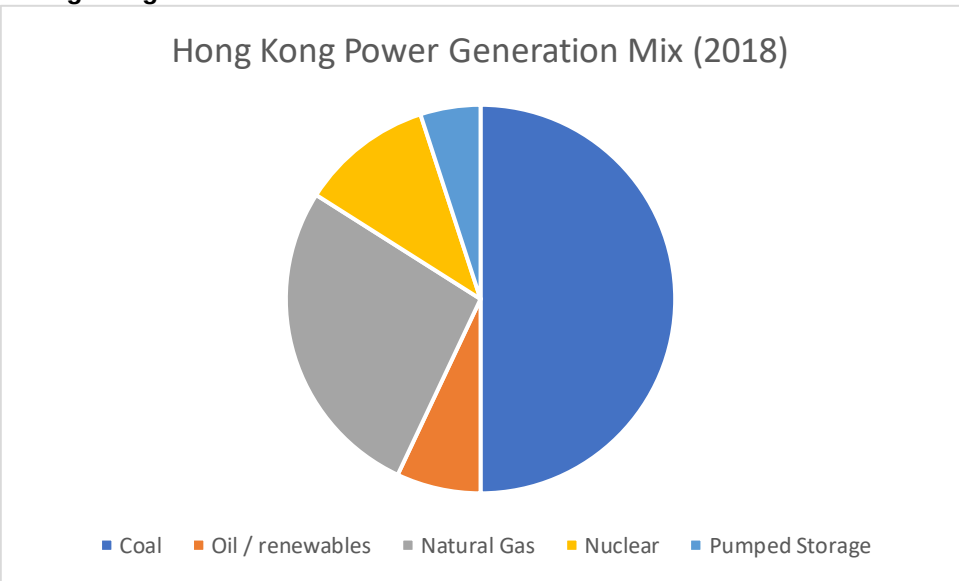
## HONG KONG

### Historic Infrastructure and Supply / Demand

The gas industry in Hong Kong has a long history, with the incorporation of the Hong Kong and China Gas Company in 1862 and first gas supply in December 1864 when Hong Kong was lit by gas with 15 miles of mains and 500 lamps.[137] The company remained registered in England until it was moved to Hong Kong in 1982, and continues to supply gas to Hong Kong and the New Territories, now under the brand Towngas. In 2019 it supplied nearly 2 million customers with a total of 28.7 PJ (7.8 TWh).[138] Towngas (as the name suggests) supplies manufactured gas (comprising around 50 per cent hydrogen, 30 per cent methane, together with CO, $CO_2$, Nitrogen and Oxygen) manufactured 61 per cent from natural gas and 38 per cent from naphtha.[139]

At end 2018, Hong Kong had total installed power generation capacity of 12,220 MW, including 80 per cent of the capacity of the 2,000MW Guangdong Nuclear Power Station at Daya Bay, and 50 per cent (600MW) of Phase 1 of the Guangzhou Pumped Storage Facility. The overall power generation capacity mix is shown in Figure 29.[140] Gas-fired power generation capacity at around 3,300MW contributed about 27 per cent of total capacity. It is notable that coal still contributed around 50 per cent of capacity, but government policy is to reduce dependence on coal.[141]

**Figure 29: Hong Kong Power Generation Mix**




Source : Author's analysis of Hong Kong Environment Bureau Data https://www.enb.gov.hk/

Use of gas for power generation started in 1996 with the commissioning of the China Light and Power (CLP) 2500 MW Black Point Power Station. Gas supply for Black Point has been from the Yacheng field offshore Hainan Island in southern China. In 2012 the Hong Kong branch of China's West to East gas pipeline system was completed, allowing additional gas supplies from Turkmenistan.

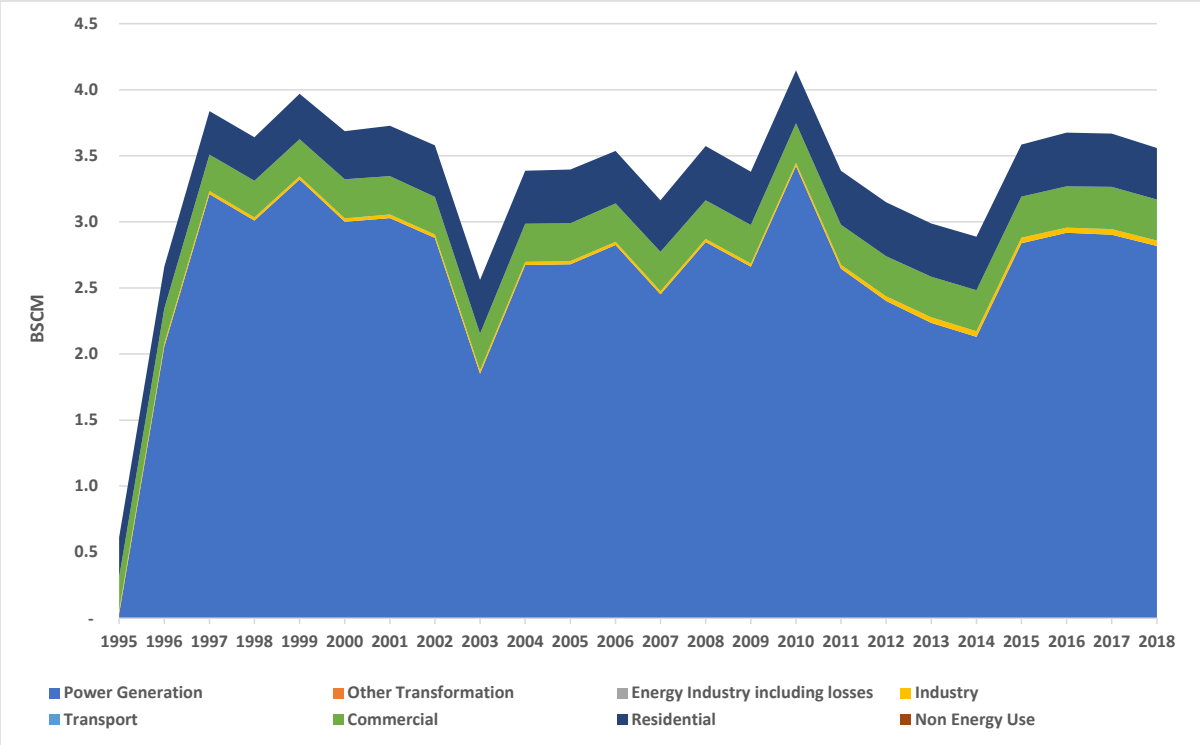
Hong Kong Electric's Lamma Power station was originally a 2,000MW coal-fired plant, but has since added additional gas-fired units totalling 700MW. Additional gas-fired combined cycle units are under construction with unit 11 (350MW) due to start operation in January 2022, and unit 12 (380 MW) due to

[137] https://industrialhistoryhk.org/hongkong-china-gas-company-early-history-1860s/
[138] Towngas annual report 29, p 30: https://www.towngas.com/getattachment/ef398302-3f27-416e-bc53-7d0eb22b525b/AR2019-Eng.pdf.aspx?lang=en-US&ext=.pdf
[139] https://www.towngas.com/en/About-Us/Hong-Kong-Gas-Business/Gas-Production
[140] https://www.enb.gov.hk/en/about_us/policy_responsibilities/energy.html
[141] See Hong Kong Climate Action Plan 2030+ (2017): http://extwprlegs1.fao.org/docs/pdf/hk177805.pdf

start operation in 2023. Gas supply to Hong Kong Electric (and to the Towngas manufacturing plant) is by a 20 inch submarine pipeline from the Guangdong LNG terminal, which regasifies LNG imports from Australia.

Since 1996 gas consumed in power generation in Hong Kong has been in the range 2.5-3.0 bcm, shown together with the gas consumption for residential and commercial use (via Towngas) in Figure 30.[142]

**Figure 30: Historic Gas Consumption by Sector**




Source: IEA

## Government Policy and Regulation

As noted above, government energy policy is largely driven by its Climate Action Plan 2030+, which envisages gas continuing to increase its share of power generation at the expense of coal. A chart in the report suggests that by 2030 gas would contribute about 60 per cent to total power generation, although no specific figure is given.

The Environment Bureau is responsible for regulation of the energy sector.[143] The government is not involved directly in the supply of electricity and gas but monitors the industry through agreements with the private companies involved. There are two Scheme of Control Agreements with Hong Kong Electric and CLP, under which the companies are required to seek approval of the Executive Council of government for key aspects of their development plans, including tariff levels. The government is envisaging opening up the power market to new entrants in future.

The Hong Kong and China Gas Company (Towngas) is regulated through an Information and Consultation Agreement. This does not directly regulate prices or profitability, but the company has to provide justification to government for any tariff increases.

## Potential LNG import infrastructure

[142] IEA (2019)
[143] See: https://www.enb.gov.hk/en/about_us/policy_responsibilities/energy.html

The Hong Kong Offshore LNG terminal project has been developed by a consortium of CLP (through its subsidiary Castle Peak Power) and Hong Kong Electric. A comprehensive Environmental Impact Assessment for the terminal was submitted in May 2016.[144] The project envisages construction of a double berth jetty in an offshore location south of Lantau Island with a 20km pipeline to HKE's Lamma Power Station and a 43 km pipeline to the Black Point Power Station. In June 2019 it was announced that the consortium had chartered the MOL Challenger, the largest FSRU in the world, with a capacity of 263,000 $m^3$. Around the same time, the consortium also entered an LNG supply agreement with Shell, although quantities under the contract have not been disclosed. The precise status of the project is unclear, but it is believed that construction is now (Q2 2020) starting with start of operations targeted for 2022.

In view of the limited demand growth potential there would seem to be limited potential for further LNG import projects to supply Hong Kong.

### Supply / Demand projections

According to the APEC Energy Outlook (7th Edition)[145], final energy demand for natural gas is projected to remain flat at around 0.6 mtoe until 2050 under a "business as usual" (BAU) scenario, or drop to 0.3 mtoe by 2050 under a 2 degrees C (2DC) scenario. Power generation demand for gas, however, is envisaged to grow from around 3 mtoe (~3.5 bcm) in 2020 to 6.7 mtoe (~10bcm) by 2035 and stay at that level until 2050 under BAU. On the other hand it would peak at around 3.8 mtoe around 2030 and fall to around 1.7 mtoe by 2050 under 2DC.

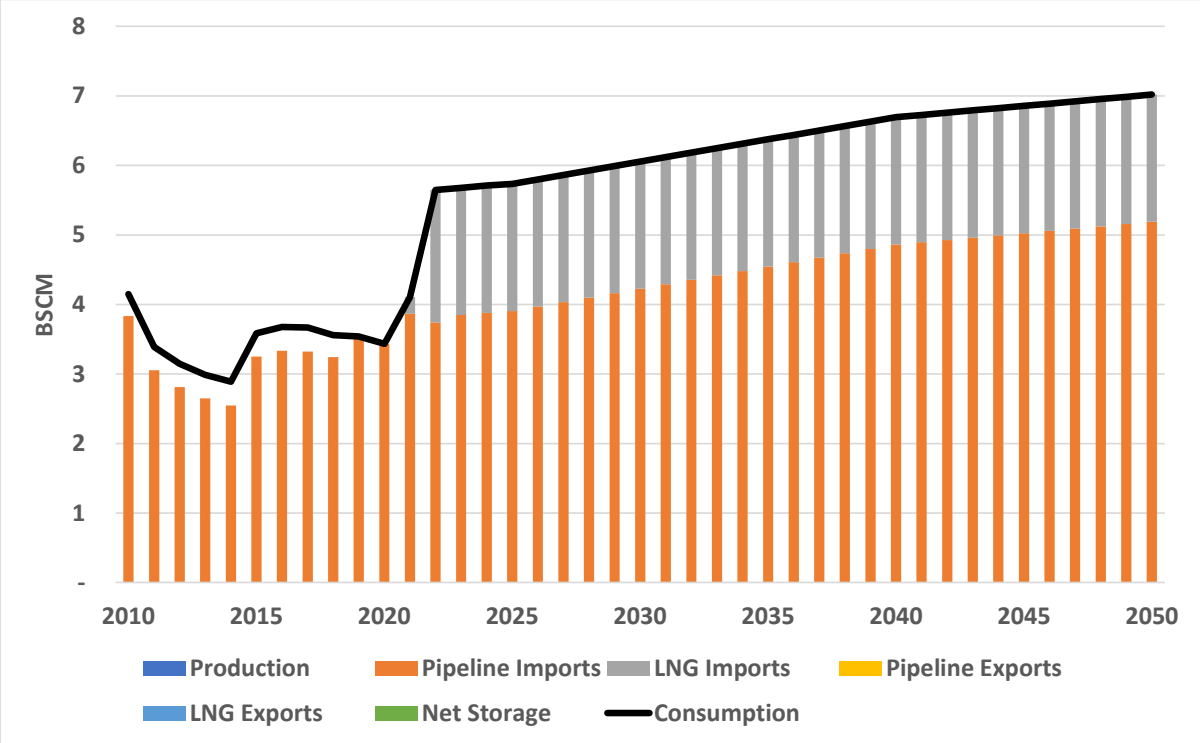
Thus, even under the most optimistic scenario, gas demand may grow by around 6 bcm from current levels. Some of this growth could be met by expansion of pipeline supplies from mainland China, although that could include additional LNG, similar to the current supply of gas from LNG via the Guangdong Dapeng LNG terminal.

## Conclusions

The main use of natural gas in Hong Kong is for power generation, and this is expected to grow in the period to 2030 in line with government policy to switch from coal to gas. There is also a small gas distribution business based on manufactured town gas. This partly uses natural gas as a feedstock, but is not expected to grow significantly from current levels. Hong Kong has been importing gas from Hainan province in China since 1996, and subsequently added gas supply from LNG regasified at the Guangdong Dapeng LNG terminal as well as supply via the West to East gas pipeline system. The Hong Kong offshore LNG terminal is currently under development and is expected to start operations around 2022. Future growth in gas demand will depend on government policy, particularly in relation to climate change and the COP21 Paris agreements. In the most optimistic case gas consumption could grow from around 3 bcm today to around 10 bcm by 2050, but in a 2 degrees C scenario could grow to around 4 bcm by 2030 before falling to below 2 bcm by 2050.

[144] https://www.epd.gov.hk/eia/register/profile/latest/esb292/esb292.pdf
[145] https://www.apec.org/Publications/2016/05/APEC-Energy-Demand-and-Supply-Outlook-6th-Edition--Volume-1

**Figure 31: Hong Kong Projected Supply Demand Balance**




Source: IEA, OIES Estimates, Nexant World Gas Model

# BANGLADESH

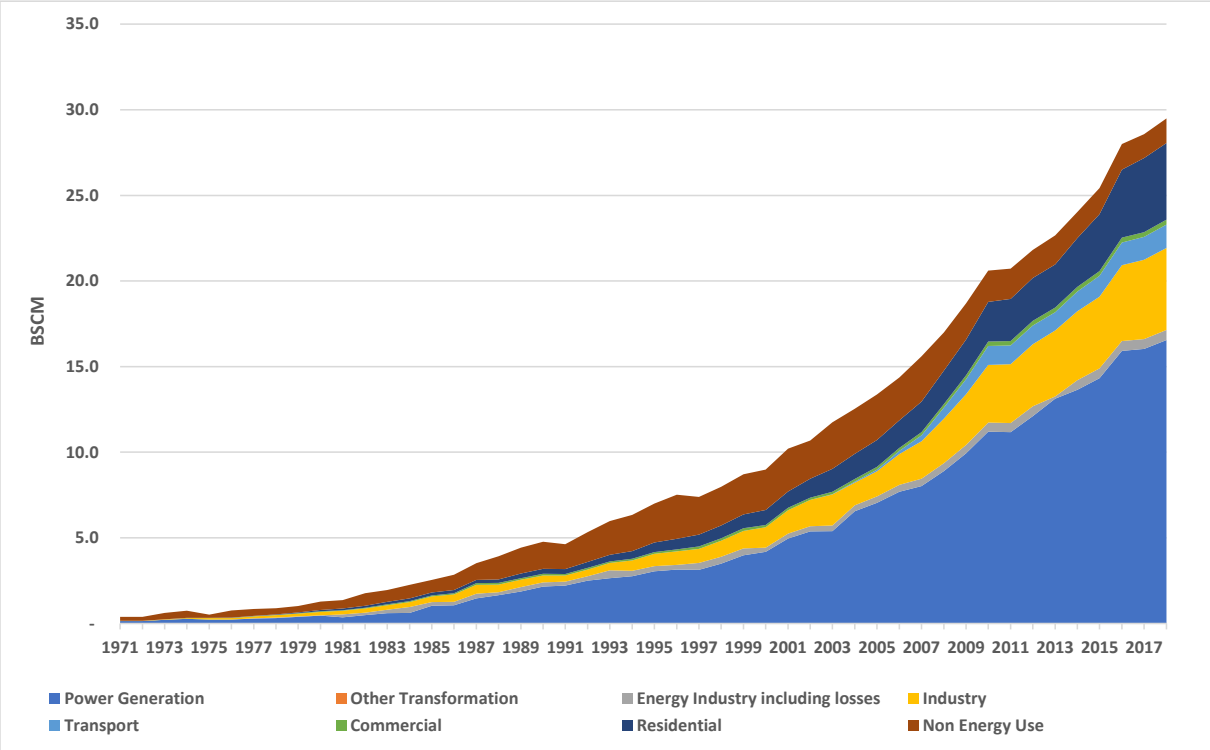
## Historic Supply and Demand

Bangladesh has a long history of gas consumption, based until recently on indigenous production. Over half the gas demand is in gas-fired power, but there is also significant use in industry (including as a feedstock for fertilizer) as well as in the residential sector for cooking and water heating, plus in NGVs in transport.

Bangladesh has relied on indigenous production up until 2018 when LNG imports began, with less than 1 bcm, rising to 4.7 bcm in 2019. Indigenous production growth stalled after 2015, and the continually rising demand is being met by LNG imports. Gas shortages, from 2015 on, forced the government to restrict gas supply to fertilizer production, businesses, households, and industrial units giving priority to state owned and privately-owned power plants. This started impeding industrial growth and development.

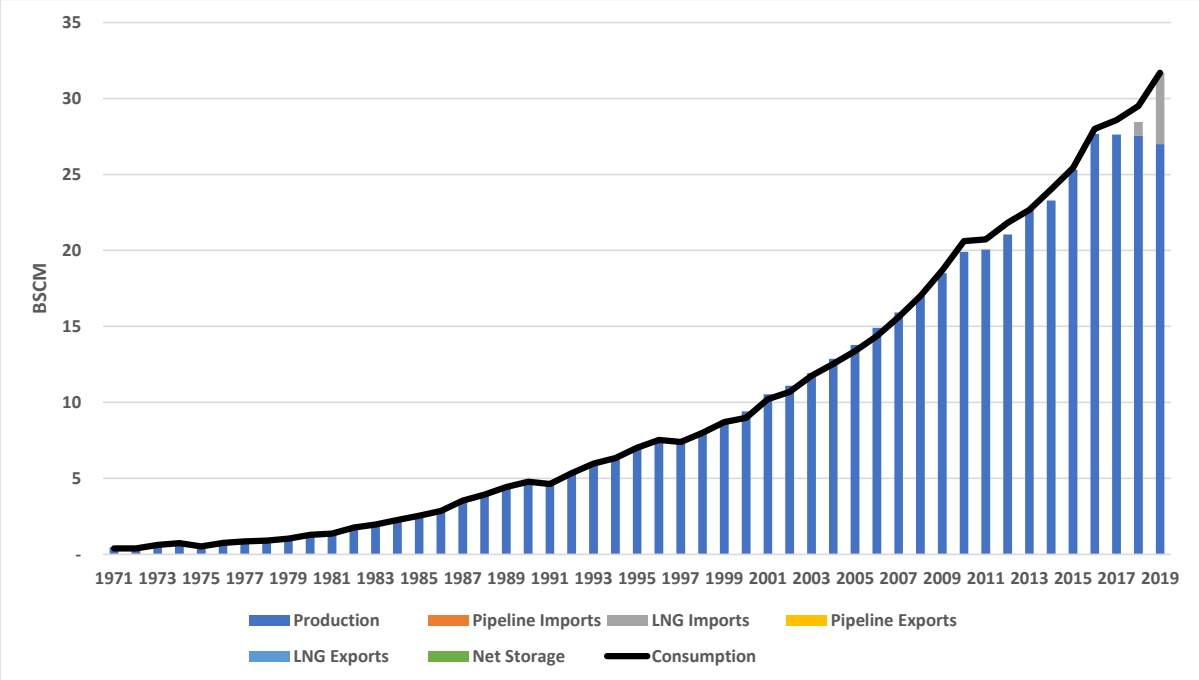
Natural gas dominates the power sector in Bangladesh, with over 80 per cent share in 2016. There is a small amount of coal in the mix, and recently oil has picked up again, as electricity demand rose.

**Figure 32: Bangladesh Gas Demand 1971 to 2018**



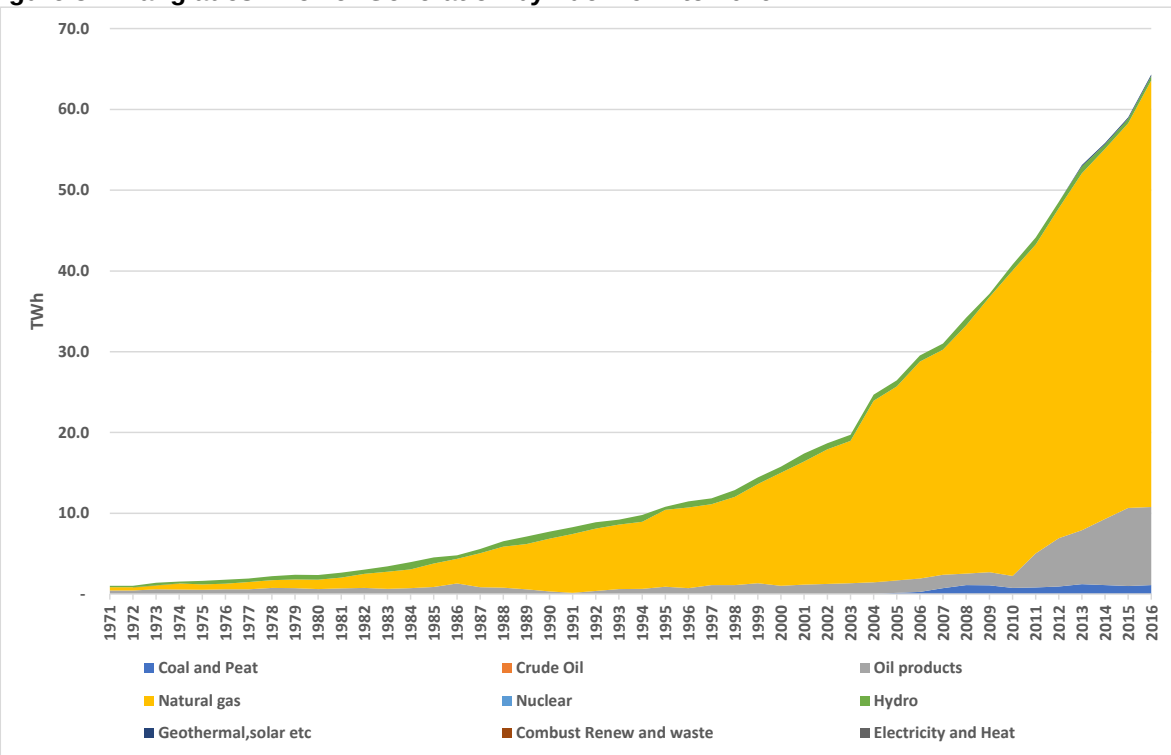

Source: IEA

**Figure 33: Bangladesh Supply Demand Balance 1971 to 2019**




Source: IEA

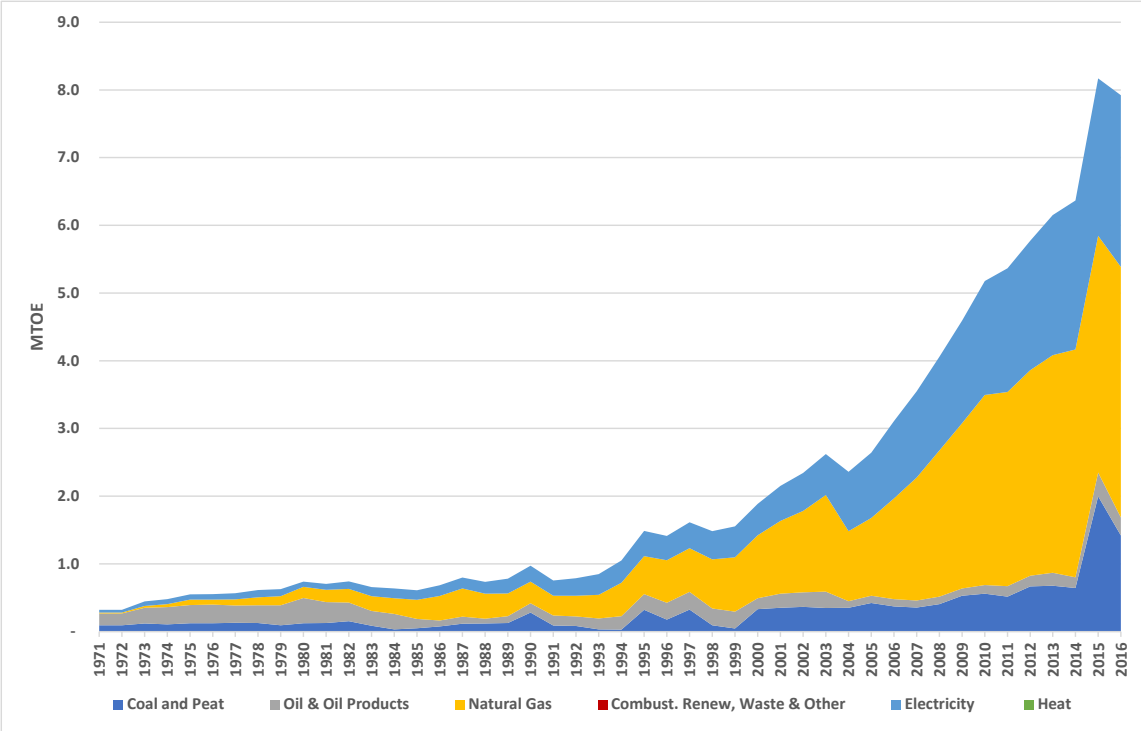
**Figure 34: Bangladesh Power Generation by Fuel 1971 to 2016**




Source: IEA

In the industrial sector, gas has almost a 50 per cent share, initially largely displacing oil products. The share has been stable for a number of years, with gas growing in line with electricity. In recent years coal use has increased.

**Figure 35: Bangladesh Industrial energy demand by Fuel 1971 to 2016**




Source: IEA

## Production[146]

Hydrocarbon exploration started in East Bengal in 1908 with the drilling of an exploratory well by Indo-Burma Petroleum Company in Sitakunda anticline (crest). During 1910-1933, six wells were drilled without any commercial discovery. The first commercially viable gas field in Chatak (Sylhet) was discovered in 1955 by the Burma Oil Company. During 1951- 1970, a total of 22 wells were drilled. Seven gas fields were discovered in 1960s (Shell Oil Company -5 gas fields and Pakistan Petroleum Ltd -2 gas fields). One gas field was discovered in 1970. After the independence of Bangladesh, twenty-four wells were drilled between 1972 and 1992 and nine gas fields and one oil field were discovered. The oil was discovered while drilling for gas at Sylhet 7 in the Haripur gas field. During 1993-2000, ten wells were drilled, and five more gas fields were discovered. During 2001-2008, two wells were drilled (one by BAPEX and another by IOC) and a gas field was discovered by IOC. From 2009 to 2018, fourteen exploratory wells (eight by BAPEX, two by SGFL and four by IOC) were drilled and four new gas fields were discovered by BAPEX[147]. The Chhatak gas field started supplying gas to Chhatak Cement Factory in 1959 ushering in commercial use of natural gas in Bangladesh. Fenchuganj Fertiliser Factory started using natural gas as feedstock supplied from the Sylhet gas field in 1961. Later (1968), Titas gas field started to supply gas to the Siddirganj gas-fired power plant. The first gas supply through the pipe network for domestic use was to the Dhanmondi residential area of Dhaka in 1968. After the Bangladesh Liberation War in 1971, the Bangladesh government headed by its Father of the Nation, Bangabandhu Sheikh Mujibur Rahman, enacted the 'Bangladesh Petroleum Act 1974'. Under this act, Bangladesh Oil, Gas and Mineral Corporation (BOGMC) was created as the national energy and mineral resources company. Later it was subdivided into the Bangladesh Oil and Gas Corporation (BOGC) and the Bangladesh Minerals Development Corporation (BMDC). Subsequently these two

[146] Indigenous and imported natural gas and the economic growth of Bangladesh: The challenges ahead. Firoz Alama, Khondkar Salequeb, Quamrul Alamb, Israt Mustarya, Harun Chowdhurya, School of Engineering, RMIT University, Melbourne, 3000, Australia; School of Business and Law, Central Queensland University, Melbourne, 3000, Australia

[147] Bangladesh Oil, Gas and Mineral Corporation (Petrobangla) Report 2018, retrieved from https://www.petrobangla.org.bd/

entities were merged to create the vertically integrated national oil and gas company “Petrobangla”. The estimated gas reserves in Bangladesh are shown in Table 5.

**Table 5: Bangladesh Gas Reserves**

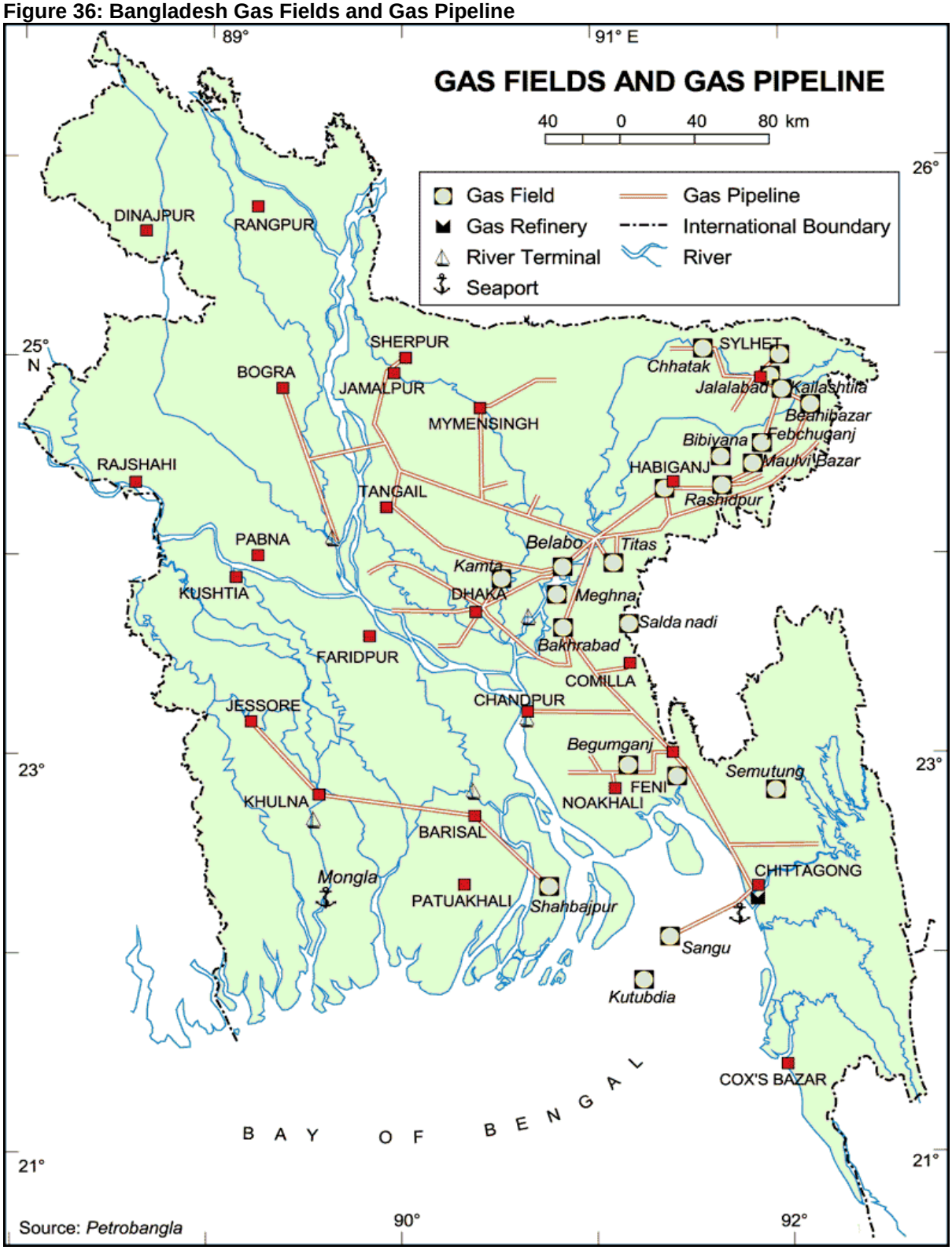
| Reserve Type | Trillion Cubic Feet (tcf) | Trillion Cubic Meter (tcm) |
|---|---|---|
| Gas Initial in Place (GIIP) | 39.80 | 1.127 |
| Proven + Probable + Possible 3P | 30.82 | 0.873 |
| Proven + Probable 2P | 27.81 | 0.788 |
| Proven 1P | 20.90 | 0.592 |
| Remaining Recoverable 2P | 11.92 | 0.338 |
| Used (Consumed) as of 30 June 2018 | 15.90 | 0.450 |

Source: Bangladesh GSMP

From 2000 to 2018 around 1 tcf of new gas was added to the national grid. Over 9 tcf (0.255 tcm) of gas from discovered gas reserves has already been used. All current producing gas fields (19 with 110 production wells) have reached their production plateau. At the rate of current consumption, the proven reserves (20.9 tcf) could be fully exhausted by 2039, or earlier if no new large gas field is discovered.

The state-owned oil, gas and mineral resources company “Petrobangla” divided Bangladesh’s entire onshore and offshore territory into 48 exploration blocks of which 22 are onshore, 11 in shallow water (near the coastal area) and 15 in offshore deep water. The government plans to expand onshore and offshore hydrocarbon exploration activities to enhance its economic development. Exploration activities so far undertaken were mostly in the eastern part of Bangladesh and shallow coastal water in the south east of Bangladesh. Almost the entire western onshore part of Bangladesh is not well explored. In addition, the deep-water region (15 blocks) remains completely unexplored.

**Figure 36: Bangladesh Gas Fields and Gas Pipeline**




Source: https://www.thebangladesh.net/gas-fields-gas-pipeline-of-bangladesh.html

## Infrastructure and Contracts

Bangladesh's first LNG import terminal opened in mid-2018 – the Excelerate Excellence FSRU – with a capacity of 3.8 mtpa. Summit LNG, Bangladesh's second LNG import terminal located offshore Moheshkhali Island (near Cox's Bazar in southern Bangladesh) began its operations in late April 2019. Excelerate's Summit LNG FSRU (formerly FSRU Excelerate previously moored in Abu Dhabi), was utilized for the project, with a regasification capacity of 3.8 mtpa.

The government of Bangladesh is planning an onshore terminal that could handle 7.5 mtpa of LNG at Matarbari in the Cox's Bazar district. The process for selecting companies to build the facility under a 20-year build-own-operate transfer basis will be conducted in 2020.

In October 2019, ACWA Power announced the signing of an MOU with the Bangladesh Power Development Board (BPDB) for an LNG-based power plant and terminal in Bangladesh. As part of the agreement, ACWA Power will target the development of a 3,600 MW gas-fired independent power plant as well as a regasification terminal located in Moheshkhali, or an alternative location.

There are plans and ideas for a number of other LNG import terminals, and the government intends to be able to import 35 mtpa by 2030. Bangladesh is a riverine delta and most of its rivers originate from the Himalayas carrying water and sediments through Bangladesh to the Bay of Bengal (Bengal Sea). This sediment discharge has created the shallow depth of nearly the entire coastal area. There are two major operational sea ports – Chittagong and Mongla – with an average navigable depth of 9m and 5 m respectively. Even the port of Payera which is under development will not have the required all season draft for providing anchorage for large LNG vessels unless dredging is undertaken around the year. Bangladesh's Matarbari, Maheshkhali and Kutubdia Islands have average drafts of 10 to 14 m and are suitable for setting up FSRUs and land-based LNG terminals for LNG import. Against this background, and the time, skills and resources required for the construction of deep-sea ports, Bangladesh has decided to go for FSRUs for the first two terminals and, as a medium-term option, a land-based LNG terminal.

The main LNG contracts for the first terminal are with Qatargas – a five year contract of 1.8 mtpa ending in 2022 and a fifteen year contract of 2.5 mtpa ending in 2032. In 2019 a ten year contract of 1 mtpa started with Oman LNG.

## Government Policy and Regulation[148]

Petrobangla is the government-owned national state oil and gas company, and reports to the Energy and Mineral Resources Division. It acquires gas from IOCs at PSC contract prices, mixes it with its own gas from subsidiaries, then transmits the gas and distributes it to its customers. Ultimately, Petrobangla is allocating gas to consumers and administering a bundled gas price set by the Bangladesh Energy Regulatory Commission (BERC).

BERC was established pursuant to the Bangladesh Energy Regulatory Commission Act, 2003. The Gas Act, 2010 ("the Gas Act" or "the Act") was passed to regulate the transmission, distribution, marketing, supply and storage of natural gas and liquid hydrocarbon in the land territory of Bangladesh and in its determined sea boundaries and economic zones. BERC was empowered to apply the provisions of this Gas Act. Prior to the Gas Act, there was no statute specifically regulating transmission, distribution, marketing, supply and storage of natural gas.

Petrobangla also has a role as the upstream regulator, supervising and monitoring the PSCs, and is the counterpart to the contracts. It is self-regulating for its own operations, including its subsidiaries. The gas produced by Petrobangla subsidiaries is sold at a gas tariff set by BERC, which includes the transmission charges to the Gas Transmission Company Limited (GTCL), which is a Petrobangla subsidiary, and distribution charges. The distribution companies sell gas to consumers at gas tariffs set by BERC.

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[148] Gas Sector Master Plan Bangladesh 2017, Ramboll, February 2018

Gas Transmission Company Limited (GTCL) was incorporated in 1993 with the objectives of (i) centralising operation and maintenance of the national gas grid; and (ii) expanding the national gas grid and as required, ensuring balanced supply and usage of natural gas in all regions of the country. Gas transmission pipelines built by other companies before the creation of GTCL have been integrated with the GTCL system. It is 100 per cent owned by Petrobangla and operates 1,560 km of gas transmission pipelines, delivering gas to the franchise areas of the Jalalabad, Titas, Bakhrabad, Karnaphuli and Paschimancahal gas marketing and distribution companies.

Titas Gas Transmission and Distribution Company Limited (TGTDCL) is the largest transmission and distribution company with a 62 per cent share of the Bangladeshi market serving 12 districts including Dhaka. It owns and operates around 450 km of high-pressure transmission pipelines, with lower capacity than those of GTCL. Petrobangla holds 75 per cent shares of this company with private shareholders holding 25 per cent.

There are five other distribution companies, of which Jalalabad Gas Transmission and Distribution System Limited (JGTDSL) owns and operates transmission pipelines, as does Karnaphuli Gas Distribution Company Limited (KGDCL), the youngest company, established in 2010.

The 2003 BERC Act gave the Commission the mandate to regulate downstream gas tariffs. The Notification on Gas Tariff Methodology, 29 December 2010, provides the procedure and methodology to gas companies to calculate and request gas tariff revisions. The methodology determines how to calculate, how to allocate average and peak costs, the cost of service for different customer classes and the calculation of Revenue Requirement for service to each class. Rate of Return for distribution licenses on qualifying assets or rate base is determined based on a calculation of the weighted average cost of capital. To determine the return on equity, the Commission gives preference to a Capital Asset Pricing Model, but allows other calculation options.

BERC sets tariffs for 7 customer classes and residential consumption, which can be metered or unmetered. These customer classes are defined in the Gas Act. Up until 2019, by international standards prices were relatively low, in particular prices paid by the power stations, which take around 40 per cent of all gas in Bangladesh, and the prices paid by fertilisers taking around 7 per cent of the gas. Other large gas consumers, captive power and industry pay around three times as much as power stations and fertiliser for the gas, but still less than in most countries. Prices were increased in 2019 as Bangladesh began to import LNG.

## Supply and Demand Projections

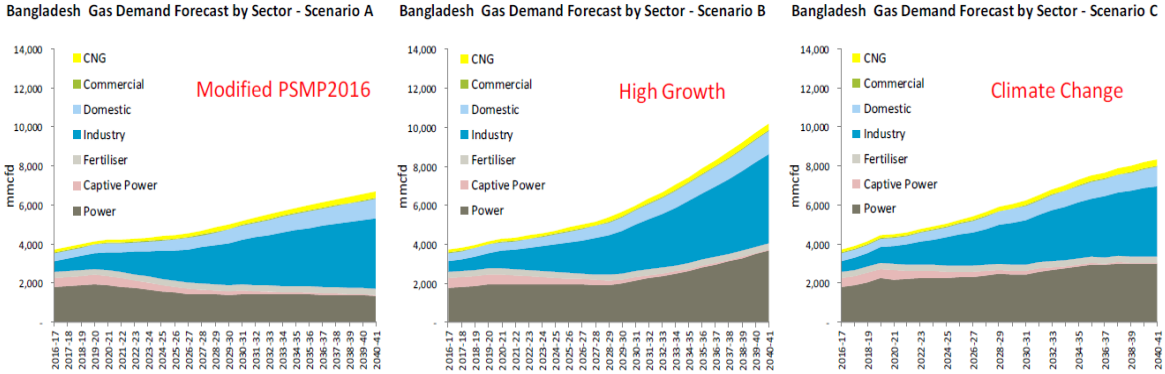
### External Demand Projections

A gas sector master plan[149] was prepared for Petrobangla and Powercell in 2018 by Ramboll, a European energy consultancy. The report concluded that there was a large unmet demand for natural gas in Bangladesh and that, with domestic production not likely to increase in the 2020s, there was a need to import gas in each and every scenario.

Figure 37 shows the different demand scenarios considered in the plan.

[149] Gas Sector Master Plan Bangladesh 2017, Ramboll, February 2018

**Figure 37: Bangladesh GSMP Gas Demand Scenarios**




Source; Bangladesh GSMP – Ramboll

The base scenario was similar to the 2016 Power Sector Master Plan (PSMP2016), with the focus on self-sufficiency and introduction of coal on a large scale. The high growth scenario was an outward looking one with a focus on gas, while the climate change scenario has renewable energies supplementing the use of gas. The latter scenario was the one that was used in the main analysis.

Scenario A projected a 70 per cent increase in gas demand between 2018 and 2040, scenario B a 150 per cent increase and scenario C a 100 per cent increase. Based on indigenous production from existing fields, production was expected to decline by over 50 per cent between 2018 and 2025, but this fall could be largely alleviated by exploiting additional resources from current producing areas, although total production would then decline post 2030. After the mid-2020s it might be possible to increase production by developing the western onshore part of the country and some of the deepwater blocks.

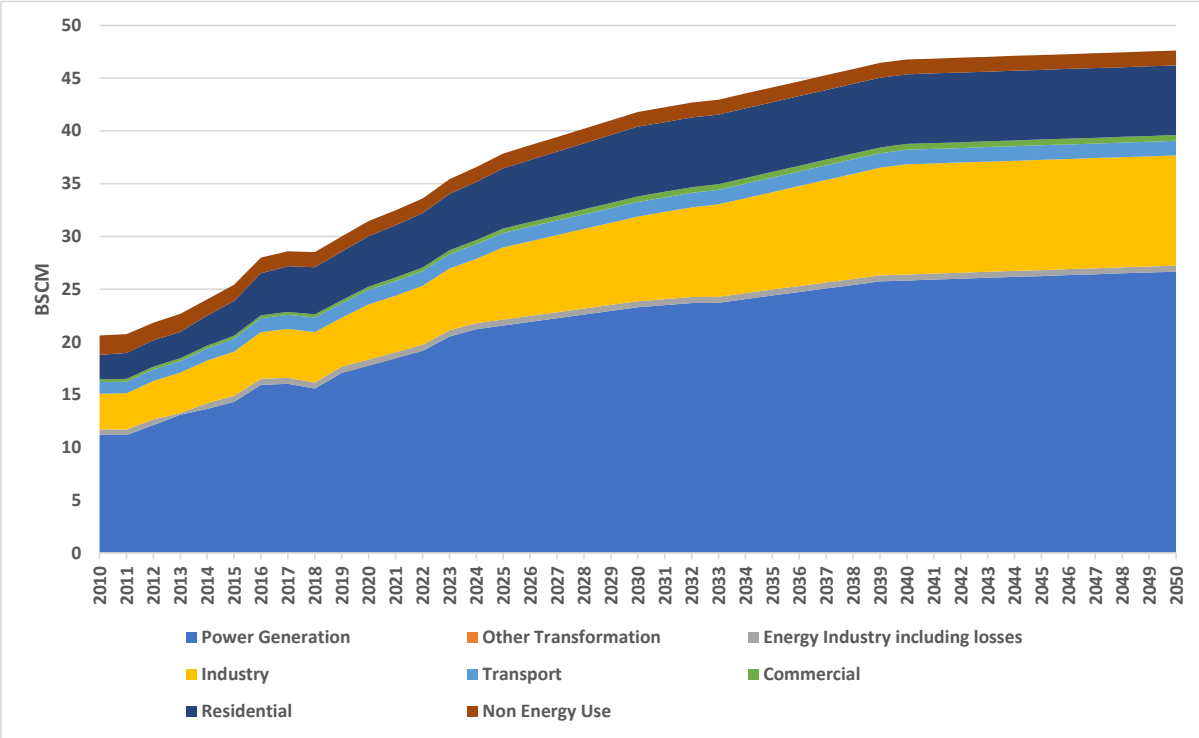
The report presented 3 cases for production. Case A, based on existing production and development of reserves in existing blocks, has an 85 per cent decline in production between 2018 and 2040 – fairly continuously. Case B, with the development of some of the shallow and deep offshore reserves, has the same fall between 2018 and 2040 but, through to 2030, the decline in production is forestalled and is a fairly flat profile. Case C on the other hand relies on the development of large amounts of yet to find reserves, which could increase production in the early 2030s significantly, before there is a decline, although by 2040 production would be at broadly the same levels as in 2018.

The wide range of scenarios for demand and cases for production will have significant implications for potential LNG imports in Bangladesh. Gas demand in 2018 was some 30 bcm with production marginally lower since LNG imports just started up that year. Based on the 2016 GSMP, demand in 2040 could be in a range from 50 bcm, through 60 bcm to 75 bcm. Production in 2040 could be close to zero or at a similar level to 2018 depending on if the yet to find reserves are developed. The shape of the production curve will also impact on the LNG import requirement over the period. In 2030 demand could range between 40 and 50 bcm and production between 20 bcm and 40 bcm. At one extreme there could be virtually zero LNG imports and at the other extreme some 30 bcm in 2030. By 2040 the range could be 20 bcm to around 70 bcm.

## Gas Supply and Demand Balance

Our Base Case demand projection is shown below. The breakdown of demand remains broadly the same as currently, with gas-fired power dominant but rising industry and residential demand. The OIES view is at the bottom end of the 2016 GSMP demand ranges, being much less optimistic on the use of gas in industry, while expecting some growth in gas in the power sector, fending off the challenge from coal.

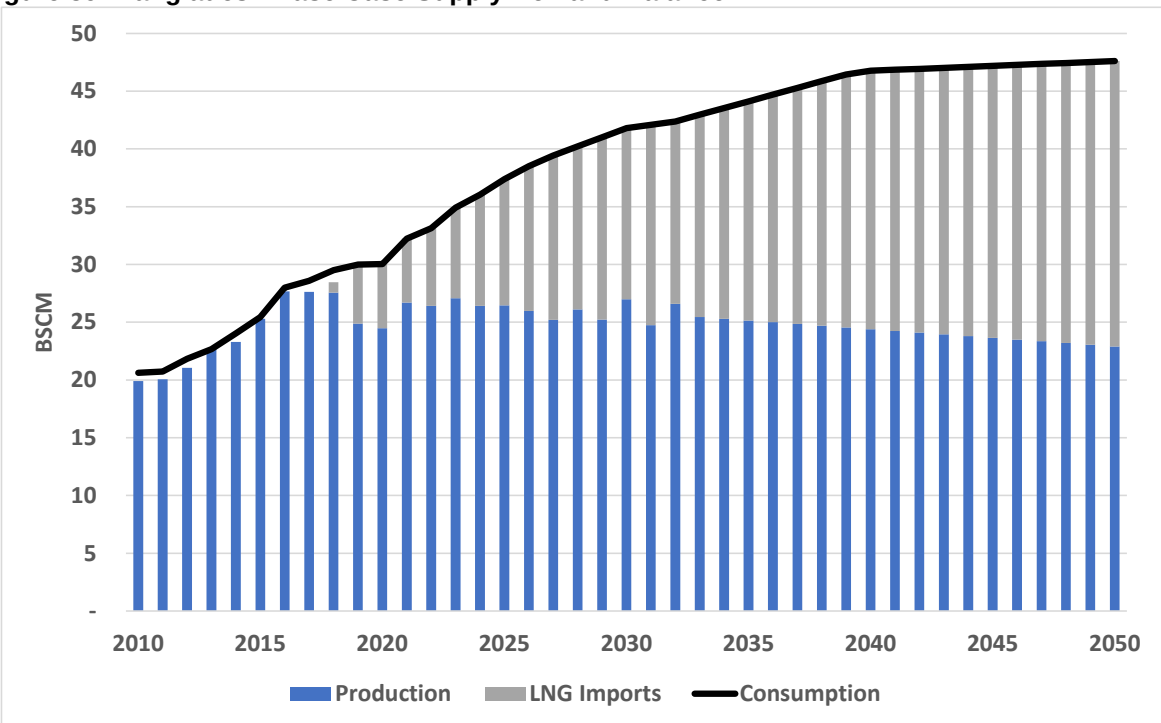
**Figure 38: Bangladesh Base Case Gas Demand by Sector 2010 to 2050**




Source: IEA, OIES Estimates

With production at best stagnating and then in decline, the rising demand leads to increasing LNG imports, reaching 15 bcm by 2030 and over 20 bcm in the longer term.

**Figure 39: Bangladesh Base Case Supply Demand Balance**




Source: IEA, OIES Estimates, Nexant World Gas Model

## Conclusions

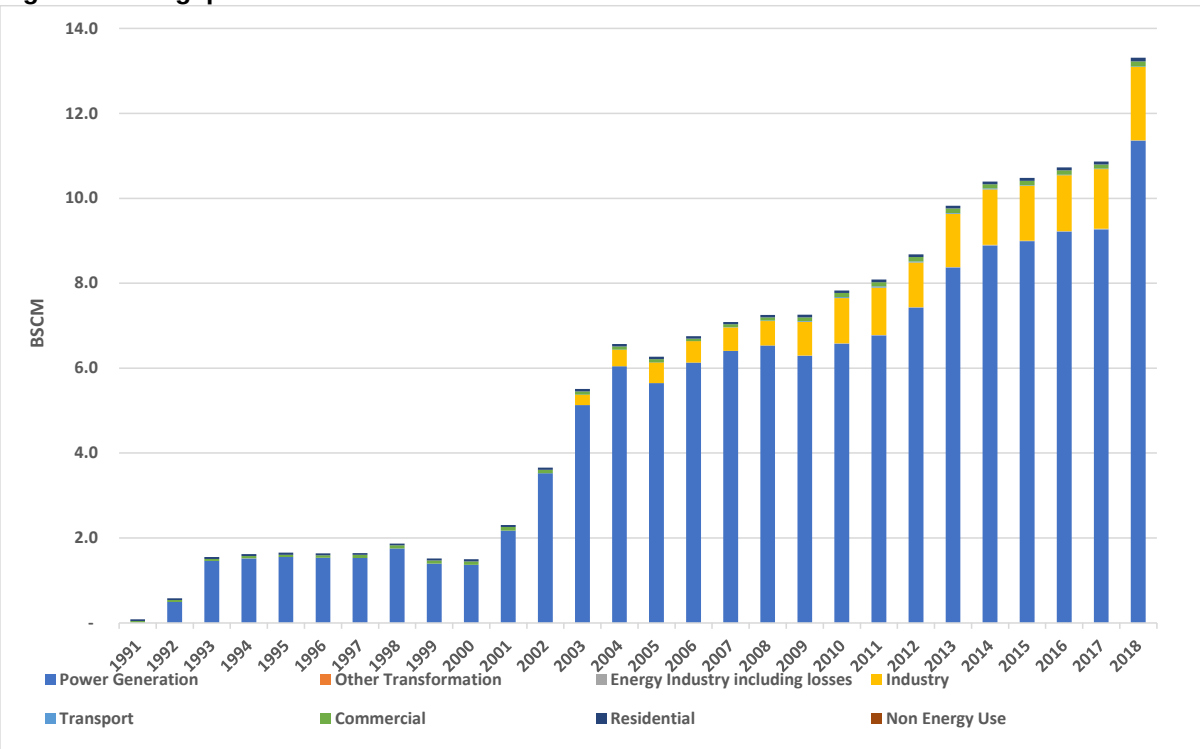
While power generation is the most important sector for gas, there is also widespread use of gas in industry, residential and NGVs in transport. With growing GDP energy demand is set to rise significantly and gas along with it. It was recognized by government that gas production was plateauing and would ultimately decline so there was a need to import gas and LNG was the chosen option. The dominance of gas in the power sector may be threatened by coal if the government were inclined to pursue that route, but the relatively low global gas prices may offset that. With a focus on dealing with climate change a move towards renewables may be more likely with gas remaining the dominant fuel in power. This suggests that gas demand could approximately double to around 45bcm by 2040 before levelling off. LNG imports may provide over half the supply by 2040.

## SINGAPORE

### Historic Supply and Demand

Singapore began consuming natural gas in 1992 in the power generation sector to displace oil in the generation mix. In 2003 natural gas consumption in the industrial sector started. Gas is also consumed in the residential and commercial sectors but this is almost all town gas produced from oil products.

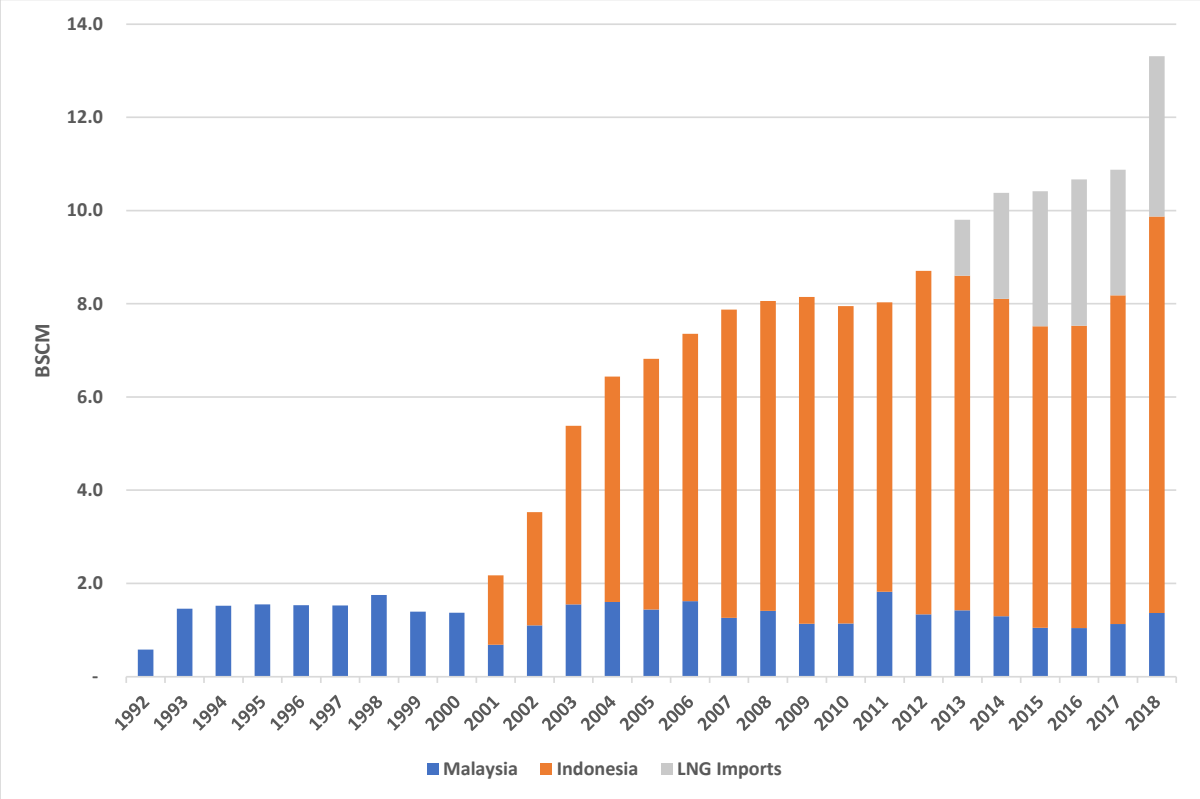
**Figure 40: Singapore Gas Demand 1992 to 2018**




Source: IEA

Singapore has no indigenous gas production and imports all its natural gas. Until LNG imports began in 2013, the gas was all imported from Indonesia and Malaysia by pipeline. Between 1992 and 2000, the only imports were from Malaysia, with imports from Indonesia beginning in 2001. Malaysian imports have averaged around 1.5 bcm/year since 1992, with Indonesia providing a much larger volume, rising to over 8 bcm/year in 2012 and 2013.

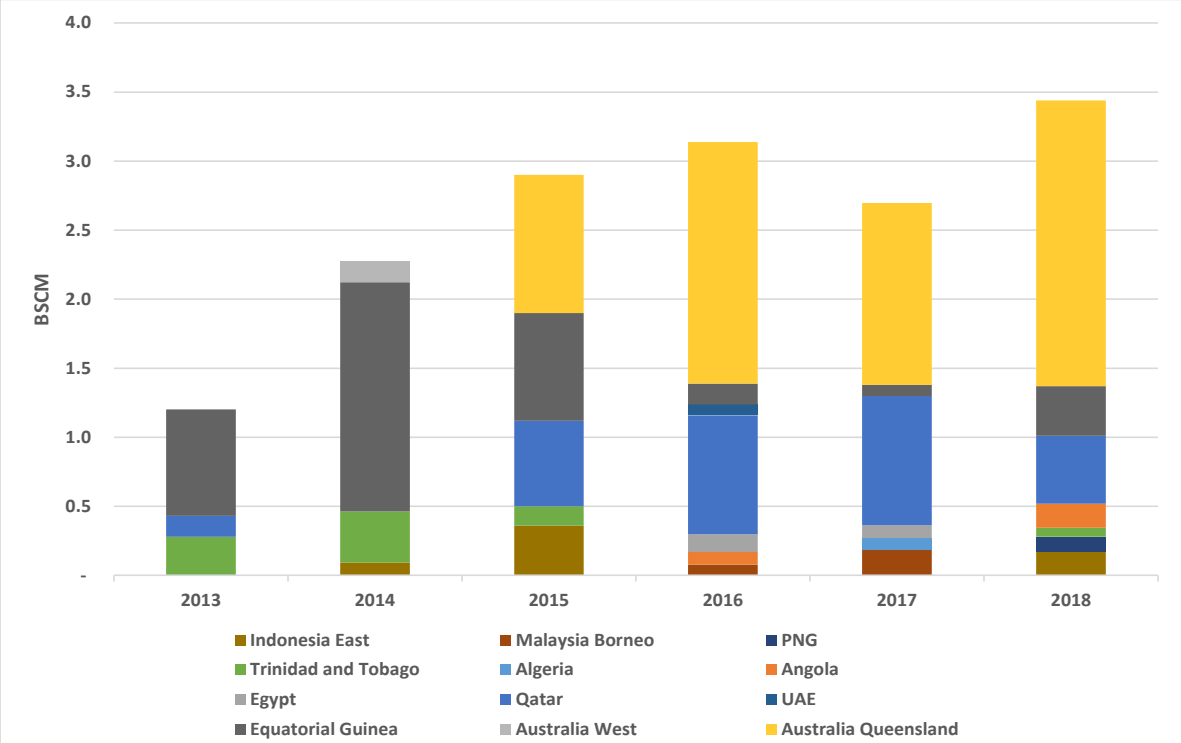
**Figure 41: Singapore Pipeline and LNG Imports 1992 to 2018**




Source: IEA

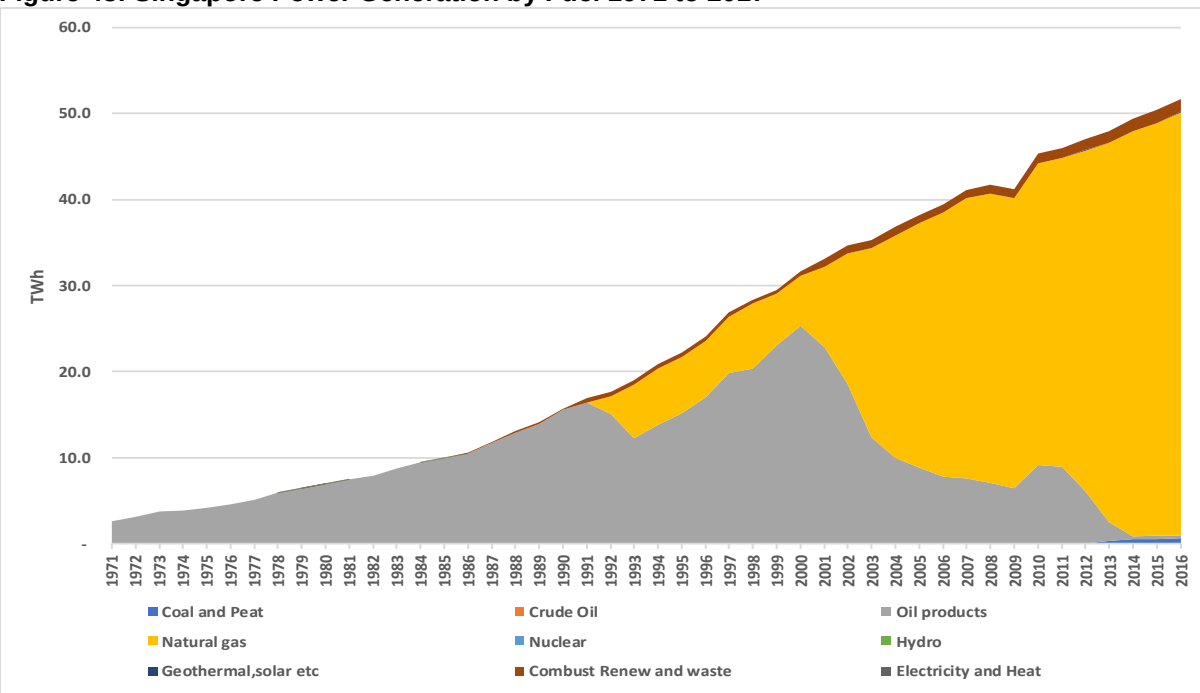
Pipeline imports began declining in 2014 as LNG imports ramped up. LNG imports have risen gradually, reaching around 3 bcm/year by 2016 and 2017. The LNG has been largely supplied under the portfolio contract from Shell (BG Group when it was signed) – see next section for more information. LNG has been supplied from a number of countries, but principally Equatorial Guinea (in the first three years), Qatar and more recently Queensland in Australia.

**Figure 42: Singapore LNG Imports 2013 to 2018**




Source: IEA

**Figure 43: Singapore Power Generation by Fuel 1971 to 2017**




Source: IEA

Natural gas was imported into Singapore to replace oil in the power generation sector. As pipeline imports from Indonesia picked up, gas had almost completely replaced oil by 2013. Currently almost all power generation in Singapore is gas-fired. There are very small amounts of coal, oil, biofuels and solar.

In the industrial sector, natural gas is used in industrial sites around Singapore.

## Infrastructure and Contracts

Singapore is connected by pipeline to Peninsular Malaysia, with an annual capacity of 4.6 bcm. There are two pipelines from Indonesia – Natuna and Sumatra – with a total annual capacity of 8.3 bcm. There were two contracts from Malaysia, one of which expired in 2018, with an ACQ of 1.19 bcm and a second one, also of 1.19 bcm ACQ which expires in 2023. There are also two contracts with Indonesia, one from Natuna – 3.37 bcm ACQ – which expires in 2022 and one from Sumatra – 3.65 bcm ACQ – which expires in 2023. With Peninsular Malaysia also now importing LNG it seems unlikely that the Malaysia contract will be renewed. The situation is more uncertain in the case of the Indonesia contracts, but it seems unlikely that both will be renewed, as Indonesia needs to consume more gas internally, as confirmed by a recent statement from the Indonesian government[150].

Singapore's Jurong Island LNG terminal opened up in 2013 with a phase 1 capacity of 3.5 mtpa. Phase 2 opened in 2014 with an additional 2.5 mtpa and phase 3 in early 2018 with additional capacity of 5.3 mtpa. Currently total capacity is some 11.3 mtpa or 15.4 bcm, which is more than total Singapore gas demand. Part of the terminal capacity was designed to be used for break-bulking cargoes for smaller scale markets. There are also proposals for a phase 4 expansion of another 3.75 mtpa. In addition, the possibility of constructing a 3.5 mtpa terminal near to Changi airport has been considered.

The initial LNG contracts came from BG Group – now part of Shell – and these were 20-year contracts starting in 2014, totalling 3 mtpa – half to Powergas and half to a consortium comprising Senoko Energy, Power Seraya, Tuas Power Generation, SembCorp Vogen, Keppel Merlimau Cogen and Island Power Company. These contracts were awarded as part of a tender process organised by the Energy Market Authority. A second process has also taken place and Shell and Pavilion Energy were chosen as the suppliers. Pavilion have signed a number of contracts with LNG suppliers:

- Total (from portfolio) – 0.7 mtpa for 10 years starting in 2018
- Total (from Sabine Pass Train 5 in US) – 0.2 mtpa for 20 years starting in 2019
- Mitsui (from Cameron in US) – 0.4 mtpa for 20 years starting in 2020
- BP (from portfolio) – 0.4 mtpa for 20 years starting in 2019

Pavilion has also signed a shorter term 5-year contract with BP for 1.17 mtpa starting in 2020 to be supplied from Tangguh Train 3, although the start-up of train 3 has now been delayed until 2021, so the contract may also be delayed unless BP supply the volumes from their portfolio.

Both Shell and Pavilion also have shorter term 3-year contracts for 1 mtpa which began in 2017 but which will end in 2020.

In the early 2020s, therefore, the total contracted LNG ACQ will be just under 6 mtpa (8.1 bcm). Once the pipeline contracts expire by 2023, the total LNG contracted will be well below current demand levels. Clearly more LNG will be needed which could be further contracted and/or purchased on the spot market.

Another option for Singapore would be to utilise the Petronas Pengerang LNG import terminal in Johor and then import the gas through the existing pipeline infrastructure.

## Government Policy and Regulation

The Energy Market Authority of Singapore151 (EMA) is responsible for supervising the Singapore gas industry. It was established in April 2001 under the Energy Market Authority of Singapore Act (Cap. 92B) as an independent regulator overseeing, among others, the gas and electricity industries. The EMA's functions and duties include:

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[150] https://www.onlinecitizenasia.com/2020/01/07/gas-supply-from-indonesia-to-singapore-will-cease-by-2023/
[151] https://www.ema.gov.sg

- Protecting the interests of consumers in prices and other terms for the supply of gas.
- Ensuring the reliability of the supply of gas.
- Promoting competition in the supply of natural gas.

To ensure a competitive electricity market, the gas industry has been restructured since 2008. Like the electricity market, the gas market is structured in a way that fosters competition. The gas transportation business is separated from the competitive businesses of gas import, shipping and retail. A set of rules called the Gas Network Code governs the activities of gas transportation, providing open and non-discriminatory access to the onshore gas pipeline network.

There are two separate gas pipeline networks in Singapore – one is for town gas that is mainly used for cooking and heating by residential and commercial customers. The other is for natural gas that is mainly used for electricity generation and industrial feedstock. Town gas is produced by City Gas Pte Ltd, whilst natural gas is imported via licensed gas importers.

PowerGas, the Gas Transporter, a member of Singapore Power Group, is the gas transporter and owns both the town gas and natural gas pipelines in Singapore. It is responsible for transporting both town gas and natural gas through its gas pipelines to consumers, who buy gas from gas shippers and retailers.

Singapore does not have any specific energy policies, with the EMA being the main regulatory body. Their focus is on energy efficiency and the expansion of solar. At the 2017 Singapore Energy Week, the Deputy Prime Minister Teo Chee Hean noted that, according to a study by the Sustainable Energy Association of Singapore, solar energy could possibly meet as much as a quarter of Singapore's energy needs in 2025[152]. However, to reach this figure, solar energy generation would have to double every two years, from generating 140 MW today to 2 GW in 2025. This seems highly unlikely, although solar is expected to increase share from a very low level.

## Supply and Demand Projections

As already noted, gas demand in Singapore is predominantly in the power sector and the gas share of power generation over 2015 to 2018 averaged 95 per cent. Fundamentally, therefore, the growth in electricity demand will drive gas demand.

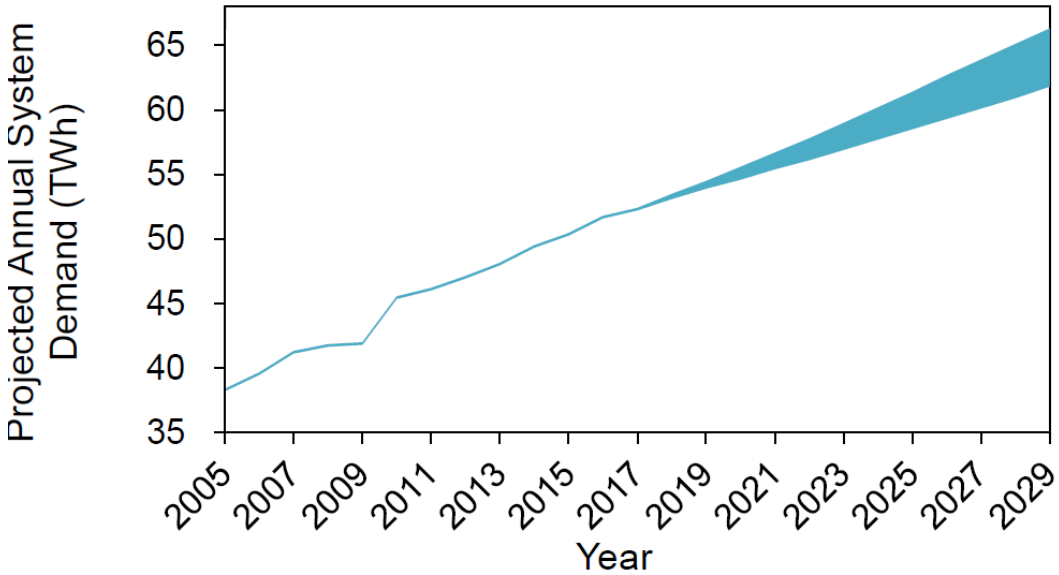
### External Demand Projections

#### *Singapore Electricity Market Outlook 2018[153]*

The latest electricity market outlook, published by the EMA, noted that Singapore's system demand had increased from about 41 TWh in 2007 to about 52 TWh in 2017 at a compound annual growth rate (CAGR) of 2.4 per cent. Over the next 10 years, from 2019 to 2029, the annual system demand and system peak demand are projected to grow at a CAGR of 1.4 – 2.0 per cent.

[152] https://home.kpmg/sg/en/home/media/press-contributions/2017/11/the-future-for-singapore-energy-burns-bright.html
[153] https://www.ema.gov.sg/Publications.aspx

**Figure 44: Singapore Annual Electricity System Demand 2005 to 2029**



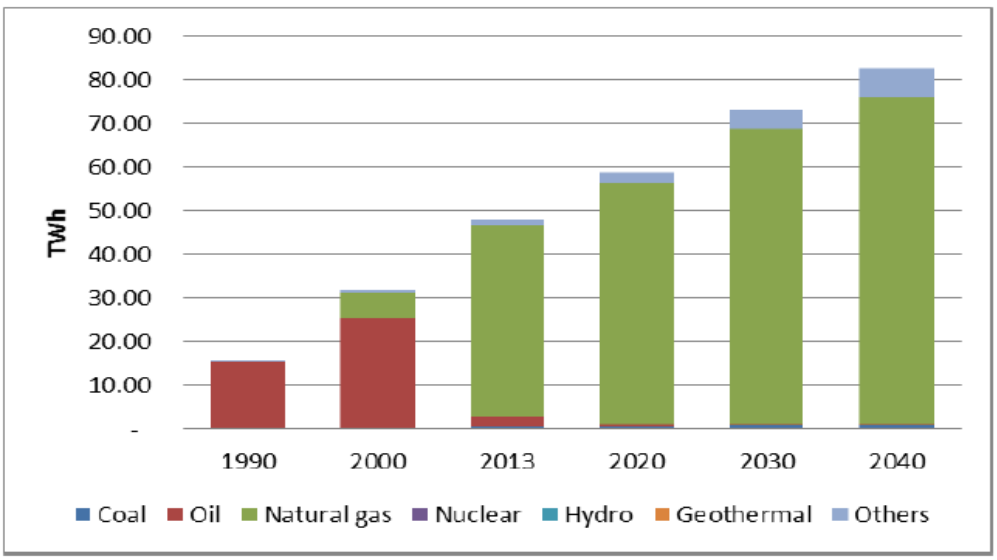

Source: Singapore Electricity Market Outlook

By 2029, total system demand is projected to be between 61.8 and 66.3 TWh. This represents a total increase of between 19 per cent and 27.5 per cent. If gas maintained its 95 per cent market share this would mean an increase from 9.72 bcm in power in 2017 to between 11.57 and 12.39 bcm by 2029.

### *East Asia Report*[154]

An earlier report looked at the energy outlook for the East Asia region. This suggested that total system demand would increase to some 72 TWh by 2030 and 81 TWh by 2040 in a Business as Usual scenario.

**Figure 45: Singapore Electricity Generation BAU Scenario**



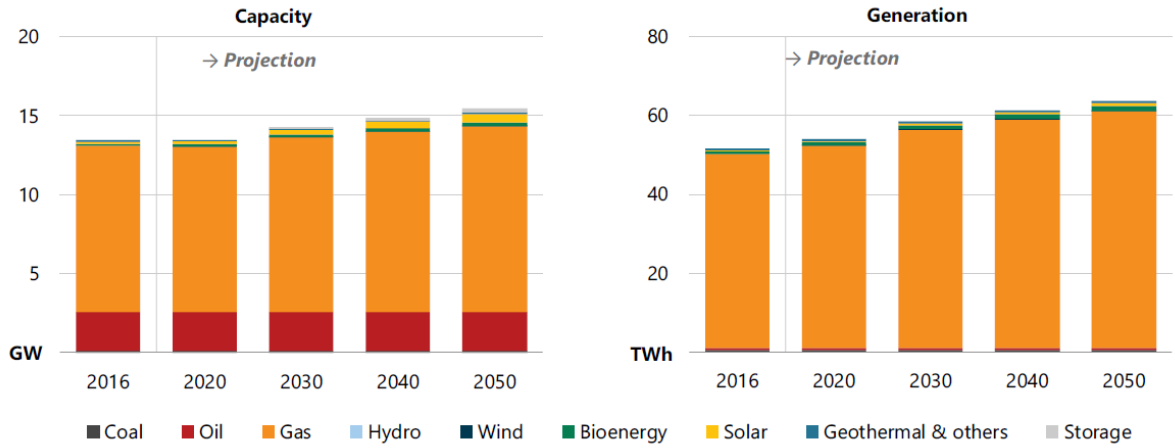

Source: East Asia Report

[154] Allan, L. and J. Tao (2016), 'Singapore Country Report' in Kimura, S. and P. Han (eds.) in Energy Outlook and Energy Saving Potential in East Asia 2016. ERIA Research Project Report 2015-5, Jakarta: ERIA, pp.297-322.

Gas was expected to maintain its market share of 95 per cent by 2030 but falling slightly to 94 per cent by 2040. This would suggest gas demand in power of 12.9 bcm by 2030 and almost 15 bcm by 2040, compared to 9.72 bcm in 2017.

### *APEC Energy Demand and Supply Outlook – 7th Edition*[155]

**Figure 46: APEC Outlook - Power Generation Capacity and Generation in BAU 2016 to 2050**

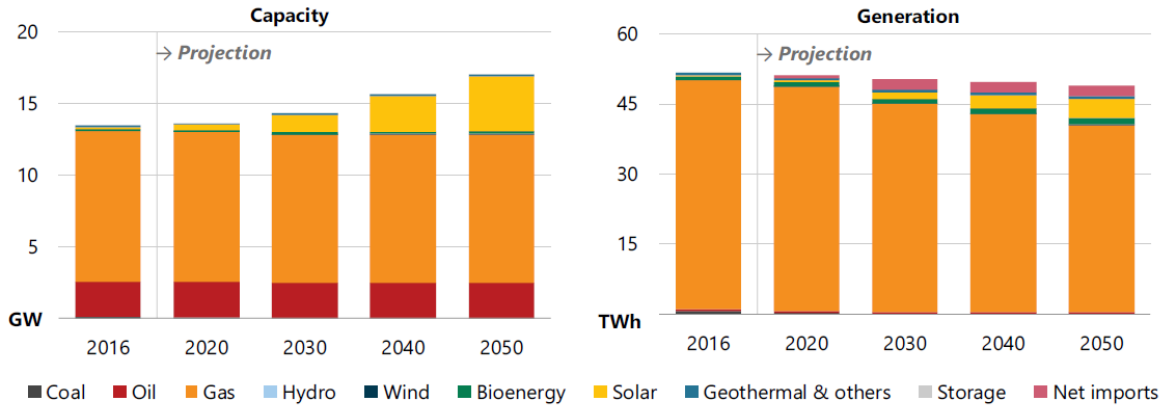



Source: APEC Energy Demand and Supply Outlook

A more recent outlook is the regular APEC energy outlook, the 7th edition of which was published in May 2019. This included a Business As Usual (BAU) scenario but also a 2 Degrees C (2DC) scenario. The BAU scenario suggested annual system demand rising to 59 TWh by 2030, 61 TWh by 2040 and 62 TWh by 2050, with gas broadly maintaining its 95 per cent market share.

This is significantly below the previous East Asia report. And suggests 11.0 bcm of gas demand in power in 2030, 11.4 bcm in 2040 and 11.6 bcm in 2050.

**Figure 47: APEC Outlook - Power Generation Capacity and Generation in 2DC 2016 to 2050**




Source: APEC Energy Demand and Supply Outlook

The 2DC scenario has a very different outlook, with generation falling to 47 TWh in 2050 compared to 52 TWh in 2017. The gas share also declines to 90 per cent in 2050. This would suggest gas demand

[155] https://aperc.ieej.or.jp/publications/reports/outlook.php

of 8.3 bcm in 2050 compared to 9.72 bcm in 2017. Gas demand would be 8.85 bcm in 2030 and 8.65 bcm in 2040 in the 2DC scenario.

Industrial energy demand in total in the BAU scenario grows by around 25 per cent between 2017 and 2050 with gas broadly maintaining its market share, suggesting total gas demand in industry rising from 1.31 bcm in 2017 to 1.64 bcm in 2050.

In the 2DC scenario, industrial energy demand growth is about half that in the BAU scenario by 2050, with a similar gas share, suggesting gas demand in 2050 of 1.47 bcm.

### *Conclusions on Demand*

The three projections discussed above resulted in somewhat different outlooks for gas demand in power by 2030. The EMA outlook suggested between 11.6 and 12.4 bcm by 2029, the East Asia outlook 12.9 bcm by 2030, and the APEC report 11.0 bcm by 2030. The APEC outlook seems to assume greater efficiency in the electricity sector than the EMA. On balance, a base case outlook might suggest around 11.8 bcm of gas in power in 2030, rising to 12.2 bcm in 2040 and 12.4 bcm in 2050, which is broadly consistent with the EMA outlook (lower end) and then the growth in the APEC outlook. In a decarbonisation scenario, such as 2 degrees C, gas demand might be 2.1 bcm lower in 2030, 2.75 bcm lower in 2040 and 3.3 bcm lower in 2050.

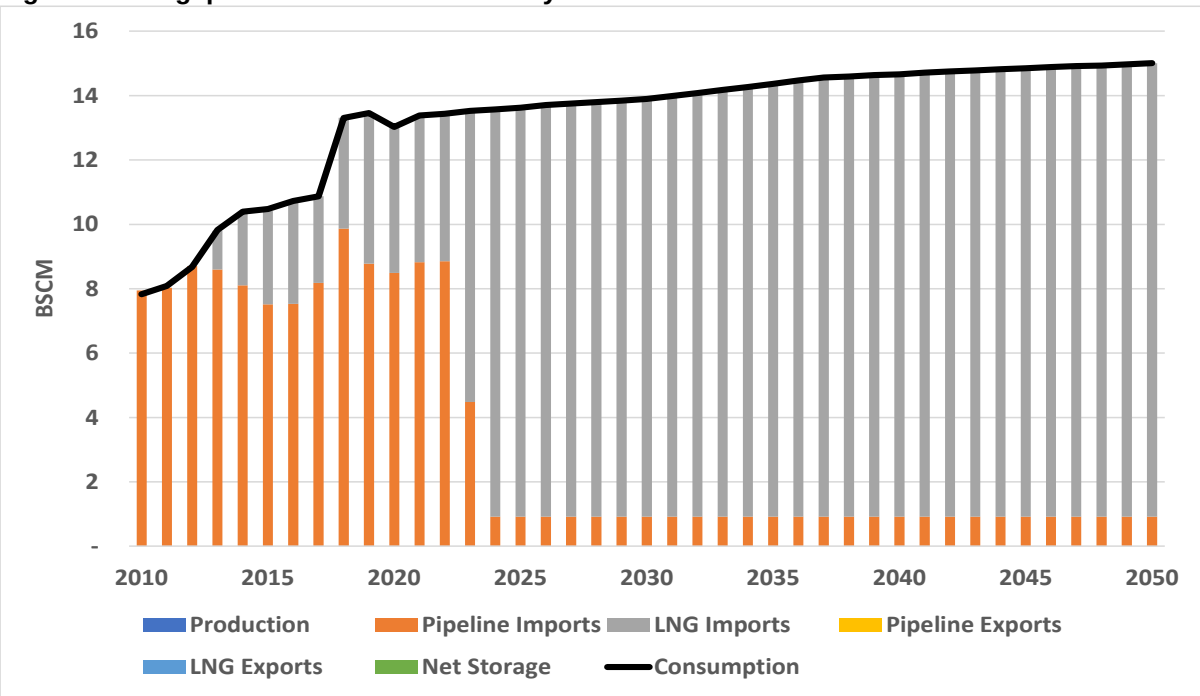
Industrial demand for gas might be around 1.44 bcm in 2030, 1.54 bcm in 2040 and 1.64 bcm in 2050 in a base case. In a decarbonisation scenario, such as 2 degrees C, gas demand might be 0.05 bcm lower in 2030, 0.10 bcm lower in 2040 and 0.17 bcm lower in 2050.

Demand in other sectors in total is around 0.2 bcm/year which can be largely added to the base case but would for the most part disappear in a decarbonisation scenario.

## Gas Supply and Demand Balance

Our Base Case supply and demand balance is shown in Figure 48. Pipeline imports by contracts from Malaysia and Indonesia end in 2023, but imports from Malaysia continue for a few years as LNG into Malaysia is re-exported by pipeline into Singapore. Demand remains predominantly in power with some growth in industrial demand.

**Figure 48: Singapore Base Case Demand by Sector 2017 to 2050**




Source: IEA, OIES Estimates, Nexant World Gas Model

## Conclusions

Gas demand in Singapore is predominantly in the power sector, with gas having displaced oil very rapidly since 2000, when piped gas from Indonesia supplemented gas from Malaysia. LNG imports began in 2013 and are expected to totally replace pipeline imports once the Malaysian and Indonesia contracts come to an end.

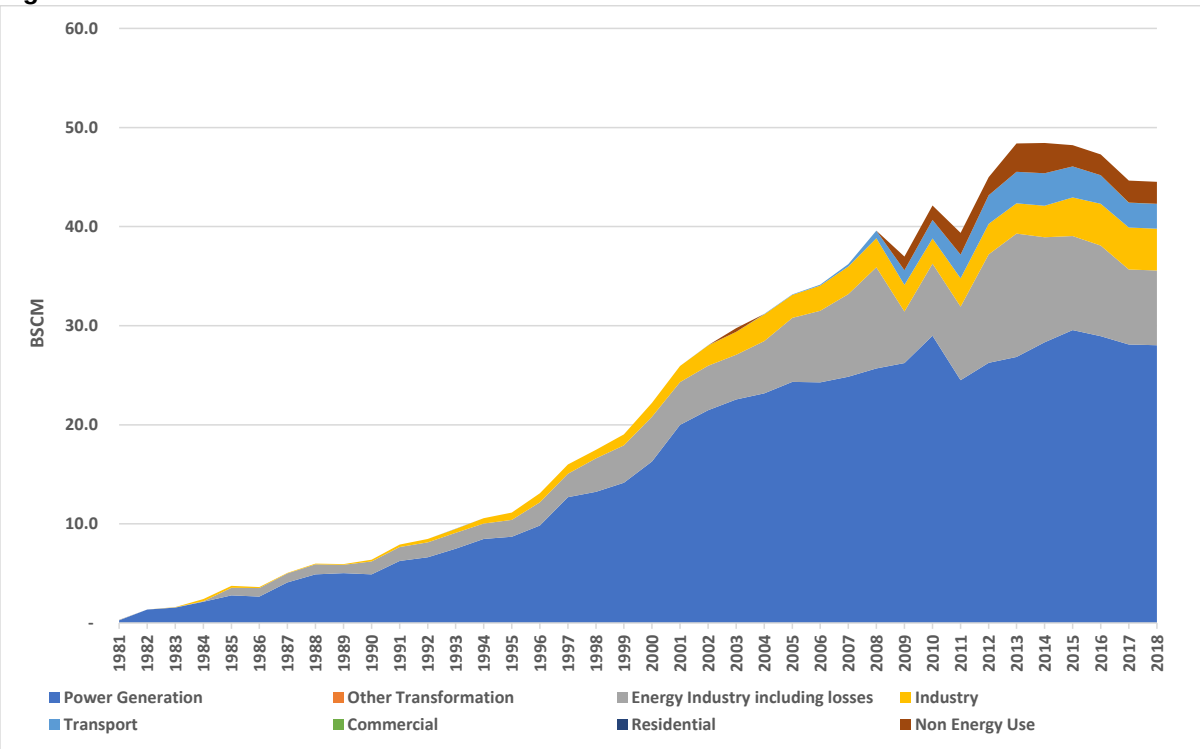
The projected demand for gas will effectively reflect rising demand for electricity. There is some scope for increasing solar generation but even in a decarbonisation case, gas is likely to remain the primary source of electricity generation.

# THAILAND

## Historic Supply and Demand

Thailand began consuming natural gas in 1981 in the power generation sector to displace oil in the generation mix, on the back of the development of domestic gas reserves. The second biggest sector is Energy Industry Use and Losses, with much smaller amounts in Industry, Transport and Non-Energy Use – feedstock. Thailand has a thriving NGV sector, which has grown particularly rapidly since 2007.

**Figure 49: Thailand Gas Demand 1981 to 2018**

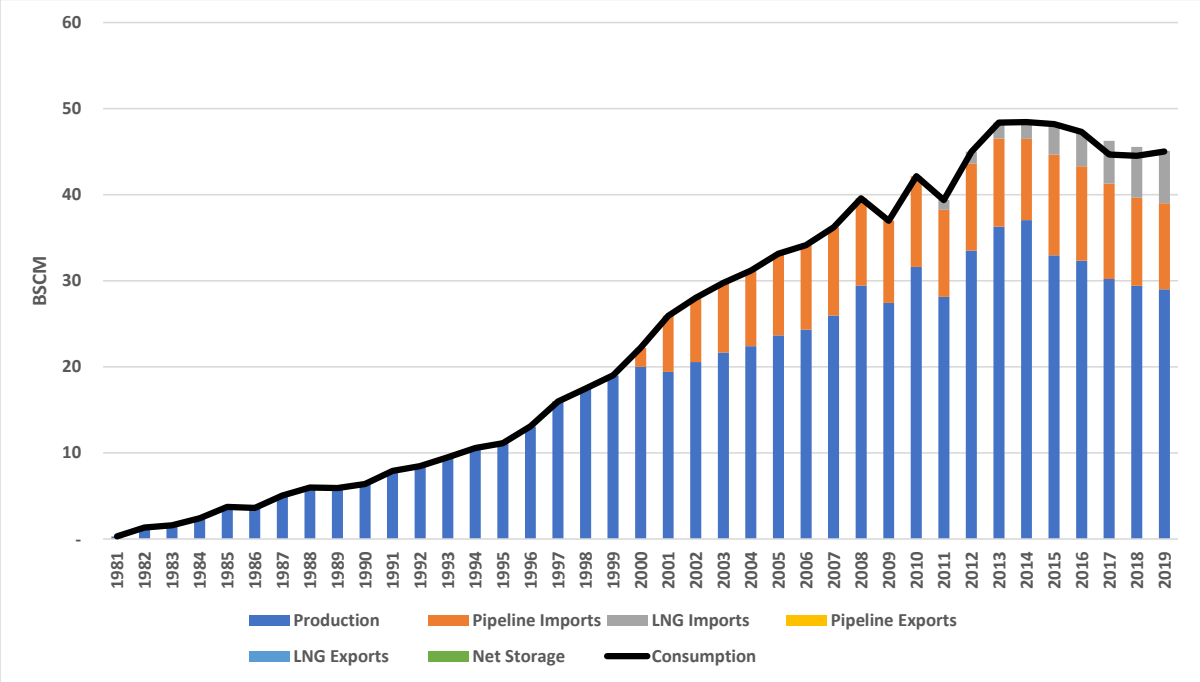



Source: IEA

The growth of gas demand in Thailand was met initially by domestic production with pipeline imports from Myanmar beginning in 1998, leading to a further surge in gas demand. As domestic production began to plateau and decline, Thailand began importing LNG in 2011, enabling demand growth to be sustained.

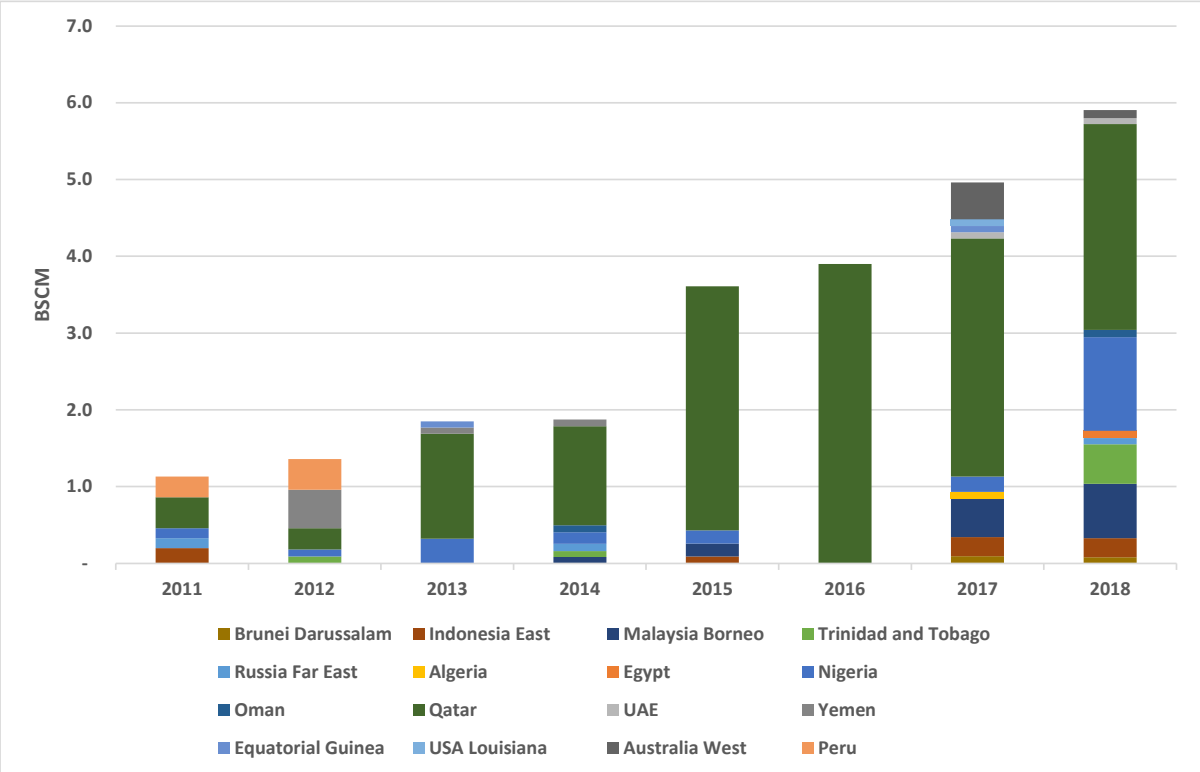
Pipeline imports have plateaued at around 10 to 11 bcm a year, with the growth in LNG imports taking up the slack. LNG imports have risen gradually, reaching over 5 bcm in 2017. Thailand initially relied heavily on short term deals and spot cargoes, until the Qatari contract began in 2015. PTT – the partly state-owned gas company – has been entering into a number of contracts with portfolio players.

**Figure 50: Thailand Supply – Demand Balance 1981 to 2019**




Source: IEA

**Figure 51: Thailand LNG Imports 2011 to 2018**

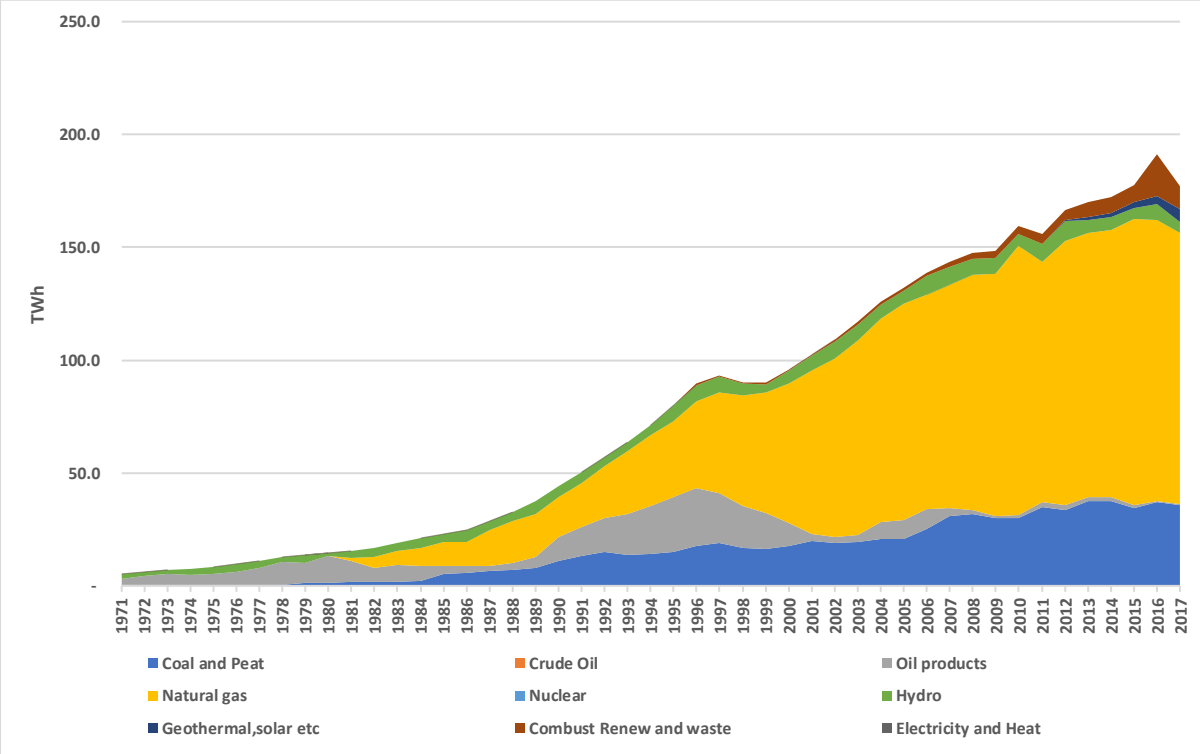



Source: IEA

Natural gas production in Thailand began in order to replace oil in the power generation sector. Gas is now the dominant fuel in the power sector, accounting for some 68 per cent of generation in 2017. Coal

has grown steadily since the 1990s, now having a 20 per cent share. Hydro has remained small, but recently there has been some growth in biofuels and solar.

**Figure 52: Thailand Power Generation by Fuel 1971 to 2017**

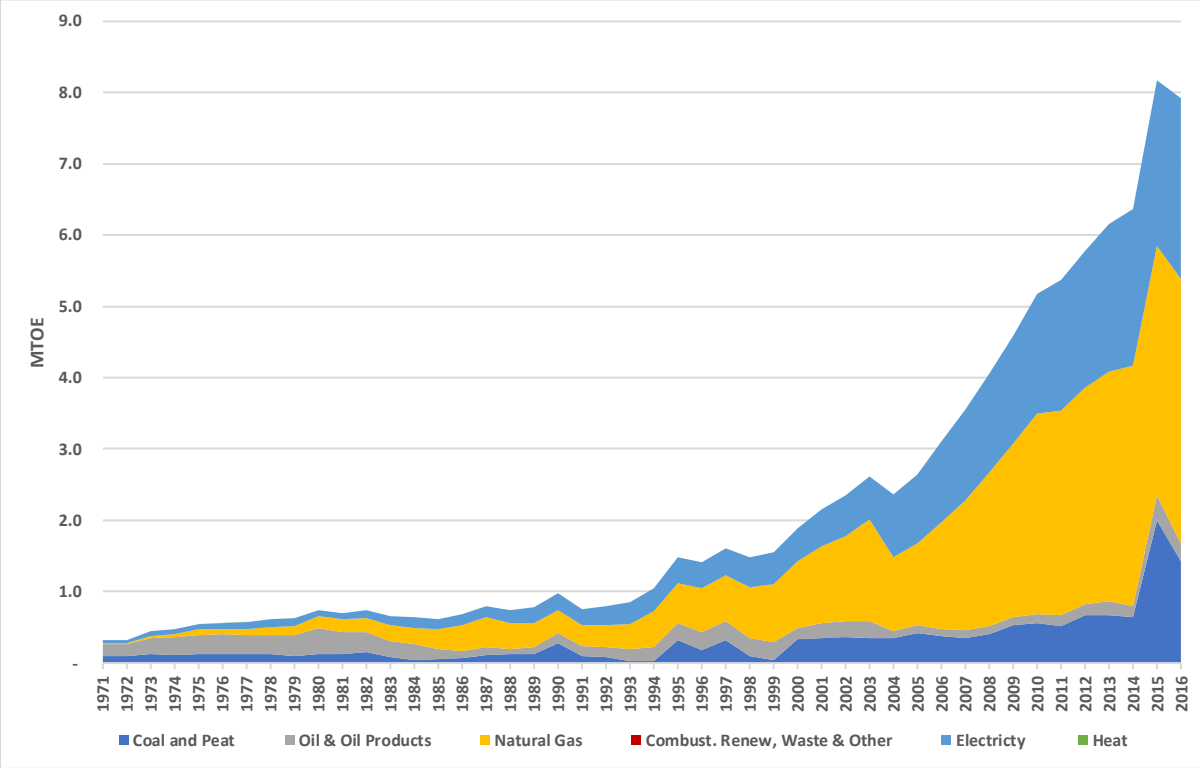



Source: IEA

Gas has made significant strides into the industrial sector. It is focussed in the chemicals and petrochemical sector, non-metallic minerals and the paper industry. The chemicals and petrochemicals sector also uses gas as a feedstock.

Coal has also recently increased its use in the Industry sector.

**Figure 53: Thailand Industrial Demand by Fuel 1971 to 2016**




Source: IEA

## Infrastructure and Contracts

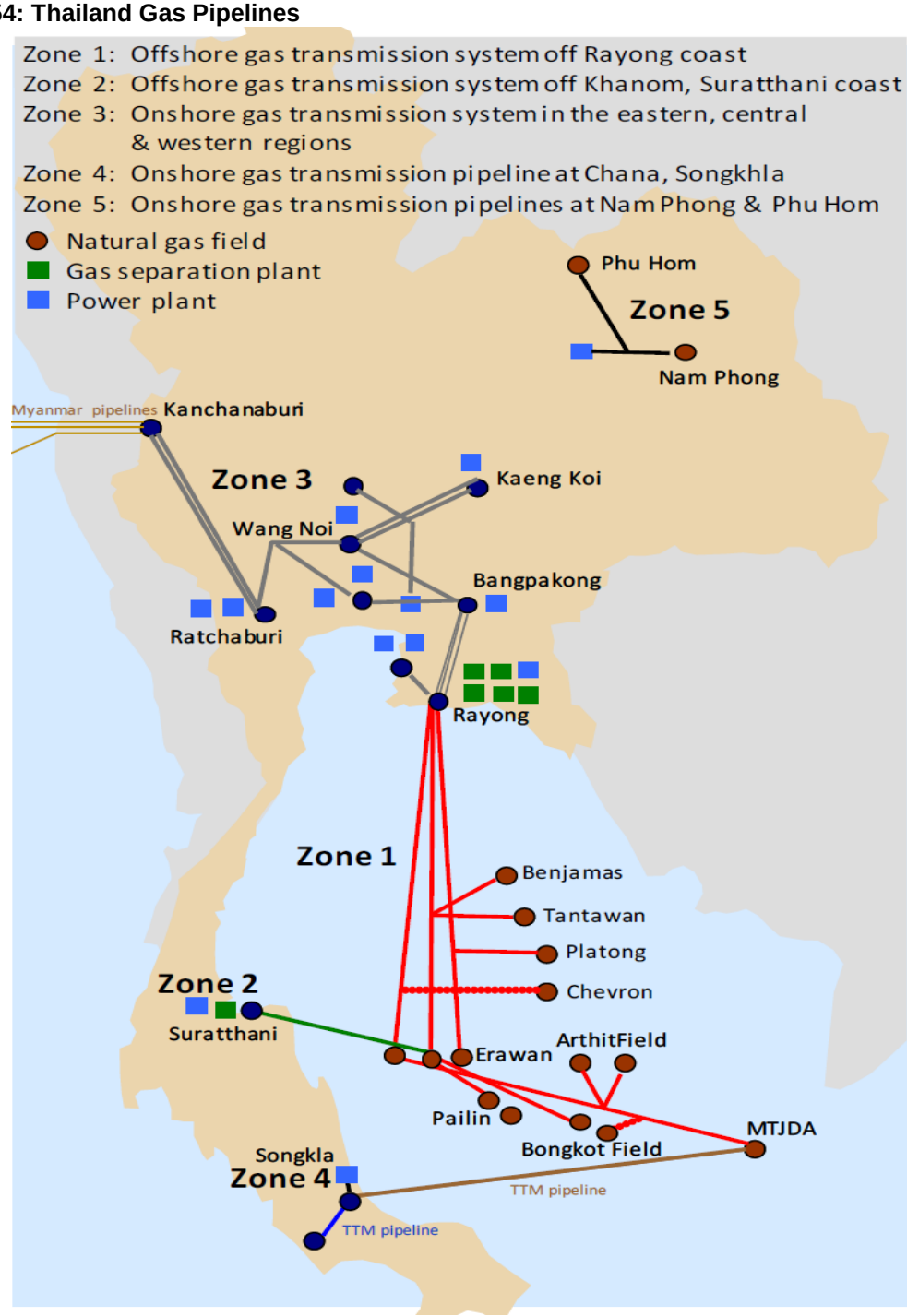
Thailand's indigenous gas supply comes largely from the Gulf of Thailand, with small volumes from the Northeast. The remaining pipeline gas is imported from Myanmar's Yadana and Yetagun gas fields.

The majority of gas produced from the Gulf of Thailand is landed in Rayong where gas is treated and subsequently delivered to customer sites (e.g. power plants, industrial plants and GSP). Small volumes are routed to Surat Thani and Sonkla provinces for power generation and also to a gas separation plant.

Myanmar gas is imported into Thailand through the West in Kanchanaburi province and subsequently delivered to power plants in Ratchaburi province. Very small volumes are produced from the ExxonMobil-operated Phu Hom and Nam Phong fields in the Northeast. The fields are not connected to the main gas grid and are sourced solely to power plant nearby.

Thailand has an extensive gas pipeline system, connecting into the Gulf of Thailand for gas from the offshore fields, including the joint development area with Malaysia.

**Figure 54: Thailand Gas Pipelines**




Source: PTT and Energy Policy and Planning Office

Thailand's natural gas transmission network is divided into five different zones as shown in Figure 54:

Zone 1: The gas transmission system offshore the Rayong coast – for transporting most of the Gulf of Thailand and MTJDA gas ashore at Map Ta Phut, Rayong province, for feeding into PTT's gas separation plants (with the volume exceeding the gas separation plants' capacities being bypassed and injected directly into the main onshore transmission network).

Zone 2: The gas transmission system offshore the Khanom coast – for transporting part of the Gulf of Thailand gas ashore at Khanom, Suratthani province, for feeding into PTT's Khanom gas separation plant (GSP #4) to extract methane for the Khanom power plant and LPG.

Zone 3: The main onshore gas transmission system spanning the eastern, central, and western regions – into which bypassed gas from the Gulf of Thailand and MTJDA, sales gas extracted from PTT's gas separation plants in Rayong, LNG and gas imported from Myanmar are injected for delivery to power and industrial plants and NGV stations

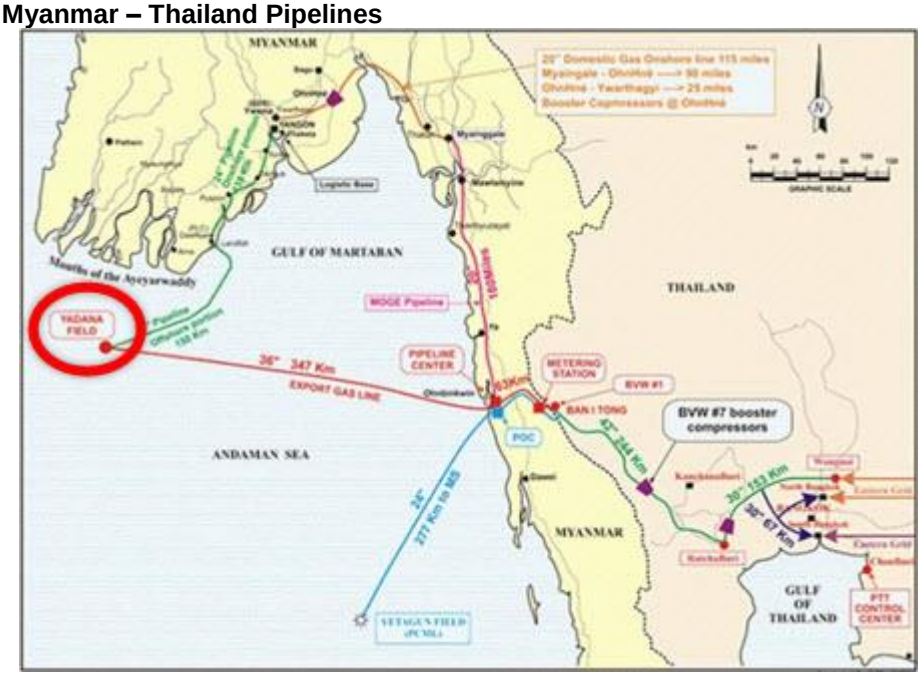
Zone 4: The onshore gas transmission pipeline at Chana, Songkhla – for delivering part of the MTJDA gas to Chana power plant

Zone 5: The onshore gas transmission pipeline at Nam Phong and Phu Hom – for delivery of the onshore gas from Phu Hom and Nam Phong fields to Nam Phong power plant in the northeast.

The purpose of zoning the network is to calculate and collect transmission pipeline tariffs.

There is also a pipeline system importing gas from Myanmar both from the onshore Myanmar pipeline system and the Yetagun and Yadana fields.

**Figure 55: Myanmar – Thailand Pipelines**




Source: 2b1st Consulting

Thailand has two gas contracts with Myanmar. One began in 1999 and ends in 2025 and has an ACQ of 9 bcm. The second began in 2013 and ends in 2042 with an ACQ of 2.35 bcm. It is not clear whether the initial contract will be renewed at the 9 bcm level, a reduced ACQ or not at all.

Thailand's first regasification terminal came onstream in 2011 at Map Ta Phut with a first phase capacity of 5 mtpa. A second phase of 5 mtpa was added in 2017 and the first phase is being expanded by another 1.5 mtpa, scheduled to come on in 2020. There are also plans to possibly expand the second phase by 3,5 mtpa but with no definitive timescale. Map Ta Phut is operated by PTT.

A number of other LNG import projects have been proposed including a Gulf of Thailand FSRU of 5 mtpa proposed by EGAT – the electricity generator, a 7.5 mtpa project at Nong Fas in Eastern Rayong province proposed by PTT and a couple of more speculative FSRUs in Chana district and Dawei district (in Myanmar but destined to supply the Thailand market) totalling 9 mtpa.

As noted earlier, Thailand purchased much of its early LNG on a spot basis or on short term contracts. The current operable contracts are:

- Qatargas – 2 mtpa for 20 years started in 2015
- BP (from portfolio) – 1 mtpa started in 2017, initially for 2 years but then increased to 15 years
- Petronas (from portfolio) – 1.2 mtpa for 15 years started in 2017
- Shell (from portfolio) – 1 mtpa for 16 years starting in 2019
- Petronas (from portfolio) – 1 mtpa for 13 years starting in 2019

All the above contracts have PTT as the buyer. PTT have also contracted with Mozambique LNG for 2.6 mtpa for 20 years when that project starts up – estimated to be 2025.

Current total contracted LNG is 6.2 mtpa with another 2.6 mtpa to come from Mozambique.

## Government Policy and Regulation

The management of Thailand's energy sector used to be undertaken by the National Energy Policy Council (NEPC), which was empowered to set the national energy policy and the national energy management and development plan as well as to monitor and supervise energy-related operations. Under the Energy Industry Act, B.E. 2550 (2007) ("the Act") the management of the energy industry was restructured by distinctly separating the functions of policy-making, regulation and operation. The Act also aimed to promote competition and enhance greater participation and the roles of the private sector, communities as well as the general public in the energy industry.

Under the Act, the Energy Regulatory Commission (ERC) of Thailand was established, to regulate the operation of the energy industry, covering the electricity industry, the natural gas industry and the energy network industry. The Office of the Energy Regulatory Commission (OERC) was also established under the Act as a state agency to function as the Secretariat to support the work of the ERC.

The ERC is empowered to issue regulations, rules, announcements or criteria, procedures and conditions in order to regulate various issues in the energy industry as prescribed by law, e.g. license granting for energy industry operation; regulation of tariff setting; establishment of energy service provision standards and safety standards of energy industry operations; protection of energy consumers' rights, including protection of energy industry operators by ensuring fair competition; utilization of immovable property for the benefit of exploration or survey of a location for construction of an energy network system; and dispute settlement. In addition, the ERC is tasked with promotion of renewable energy and efficient use of energy.

In 2015 the Ministry of Energy put forward a Gas Plan with the following objectives:

- Mitigate impact from rising gas cost from LNG import via price signaling to contain gas demand
- Ensure fair pricing of Gas/LPG for Thai people and businesses
- Maximize domestic gas production
- Ensure effective and efficient LNG sourcing
- Assure sufficient coverage and access to gas infrastructure
- Reduce unnecessary gas usage and promote gas energy efficiency

The plan expected slower gas consumption growth, together with a focus on maintaining indigenous gas levels, managing LNG supply, building the necessary infrastructure and promoting competition with the introduction of TPA. The plan expected a significant increase in LNG imports.

In early 2020, EGAT imported its first LNG cargo, followed by a second one in April, under TPA to PTT's LNG facilities and pipeline system. This is part of EGAT's three-year plan to import spot LNG, rather than rely on buying gas from PTT, taking advantage of very low spot prices. As noted above, EGAT plan to develop their own import terminal.

## Supply and Demand Projections

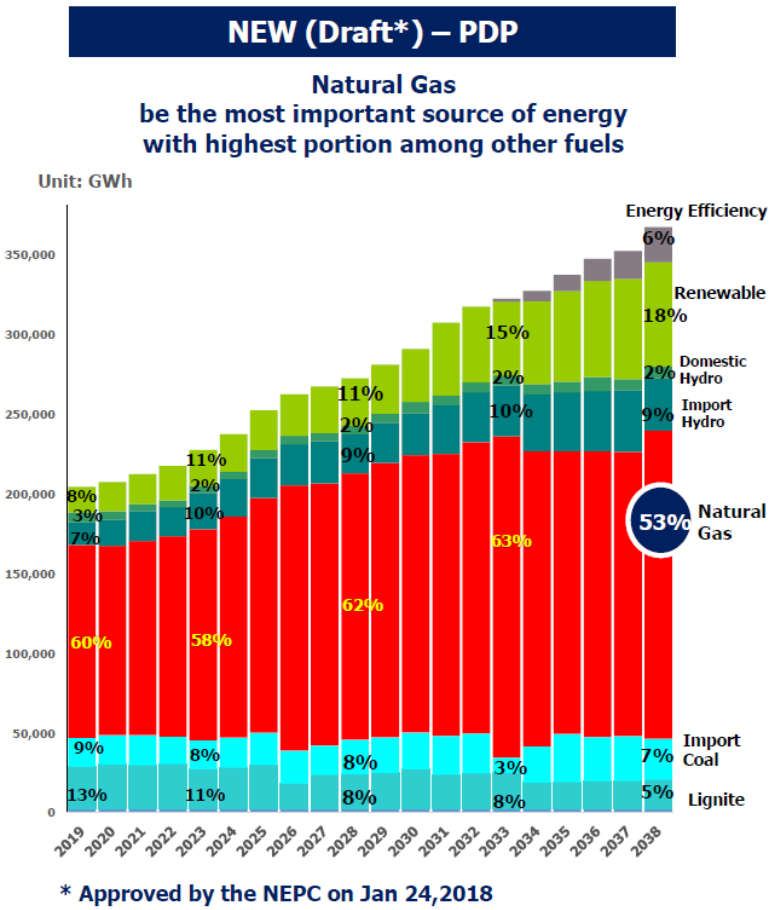
As already noted, the main source of gas demand in Thailand is in the Power Sector, although there are important sources of demand in the Energy Industry itself, Industry (including as a feedstock) and Transport.

### External Demand Projections

#### *Power Development Plan 2018*[156]

Natural gas accounted for some 68 per cent of total generation in 2017. The most recent published Power Development Plan 2018 sees a much larger role for natural gas than in previous plans. For the most part natural gas is expected to have a share of around 60 per cent through the early 2030s before declining to close to 50 per cent. This decline is principally due to the assumption of an increasing share of renewables from something like 5 per cent to around 20 per cent by the late 2030s. The share of coal also declines to some 12 per cent in total from 20 per cent currently.

**Figure 56: Thailand Power Development Plan 2019 to 2038**




Source: PDP 2018

Total generation requirement rises significantly from under 200,000 GWh currently to 300,000 GWh by 2030 and 350,000 by 2038. In 2017 gas generated some 120,000 GWh using 29 bcm. A 60 per cent share of 300,000 GWh by 2030 is some 180,000 GWh – a 50 per cent rise over 2017. With the same generation efficiency this would suggest some 44 bcm of gas demand in power. By 2038 the gas share

[156] https://af.reuters.com/article/commoditiesNews/idAFL3N22C2O8

is 53 per cent out of more than 350,000 GWh which would be around 190,000 GWh, slightly above the 2030 level at 46 bcm.

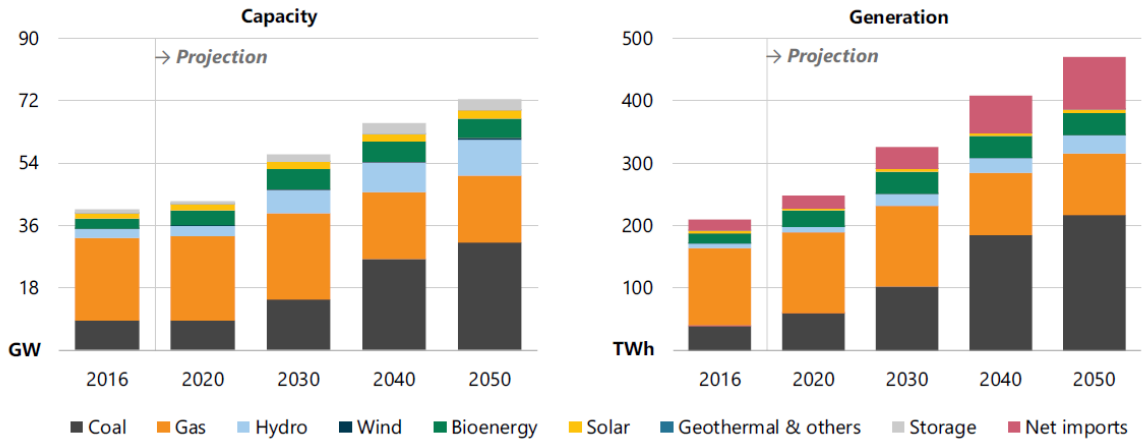
### *ERIA/IEEJ 2018 Report*[157]

The ERIA/IEEJ report included a number of scenarios for the ASEAN region. The level of power generation was the same in all scenarios at some 250,000 GWh by 2030 with gas having a 64 per cent share, which is 160,000 GWh, which is less than the Power Development Plan figure. 160,000 GWh would imply some 39 bcm of gas demand. Other sectors would add between 25 and 35 bcm depending on the scenario.

### *APEC Energy Demand and Supply Outlook – 7th Edition*[158]

A more recent outlook is the regular APEC energy outlook, the 7th edition of which was published in May 2019. This included a Business As Usual (BAU) scenario but also a 2 Degrees C (2DC) scenario. The BAU scenario suggested annual system demand rising from some 200 TWh to 310 TWh by 2030, 400 TWh by 2040 and 470 TWh by 2050 – figures which are slightly higher than the Power Development Plan 2018 numbers. The gas share is some 120 TWh in 2030, 100 TWh in 2040 and 2050. It is noticeable in the APEC Outlook that coal generation grows rapidly, which is in sharp contrast to the Government's Power Development Plan 2018, although more in line with earlier Thai government plans, which have much larger coal shares.

**Figure 57: APEC Outlook - Power Generation Capacity and Generation in BAU 2016 to 2050**




Source: APEC Energy Demand and Supply Outlook

This would suggest 29 bcm of gas demand in power in 2030 – the same as 2017 and 24 bcm in 2040 and 2050. The APEC Outlook foresees the industry sector (including non-energy use), continuing growth by over 50 per cent between 2016 and 2050, which would suggest the total of industry and non-energy use growing from 6.4 bcm in 2016 to around 10 bcm in 2050.

The 2DC scenario has a lower outlook for generation, of under 300 TWh in 2030, 340 TWh in 2040 and 370 TWh in 2050. The gas share is 110 TWh in 2030, the same in 2040 including abated with CCS and 100 TWh in 2050 also partly abated with CCS. This would suggest gas demand of 26.5 bcm in 2030 and 2040 and 24 bcm in 2050 in the 2DC scenario. A key difference between the BAU and 2DC scenarios is the reduction in coal and the elimination of unabated coal.

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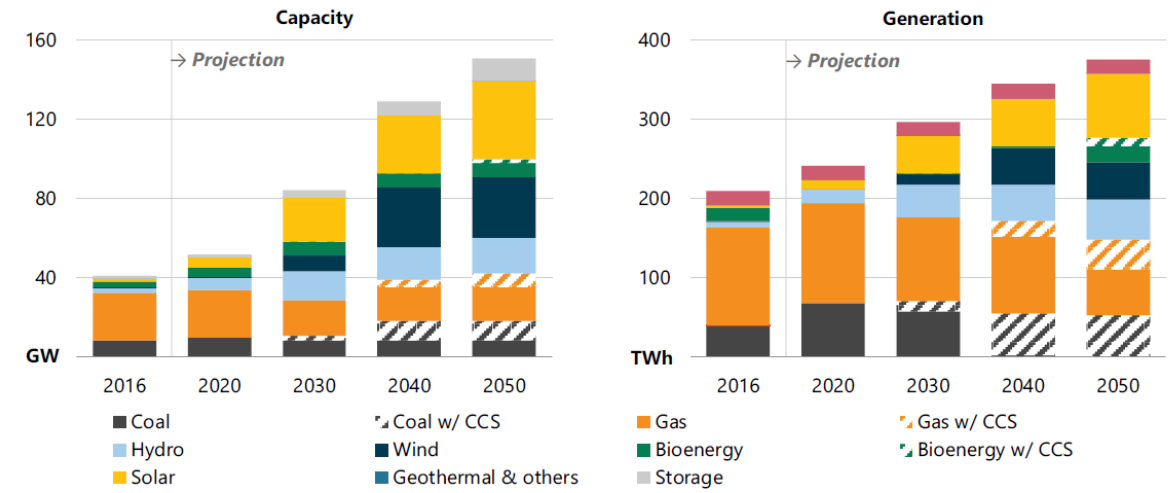
[157] Final Report on Potential Natural Gas Demand in ASEAN. *Economic Research Institute for ASEAN and East Asia, The Institute for Energy Economics in Japan.* March 2018

[158] https://aperc.ieej.or.jp/publications/reports/outlook.php

**Figure 58: APEC Outlook - Power Generation Capacity and Generation in 2DC 2016 to 2050**




Note: CCS = carbon capture and storage.

Source: APEC Energy Demand and Supply Outlook

In the 2DC scenario, industrial energy demand growth is only slightly below the BAU scenario by 2050, with a similar gas share, suggesting only a small reduction in gas demand.

Conclusions on Demand

The three projections discussed above resulted in very different outlooks for gas demand. For 2030, the PDP 2018 suggested gas demand in power of 44 bcm, the ERIA/IEEJ report some 39 bcm and the APEC BAU scenario some 29 bcm. By 2040 the PDP may be around 46 bcm with the APEC BAU scenario at 24 bcm, continuing to 2050. The key difference seems to be the high level of coal generation in the APEC BAU scenario.

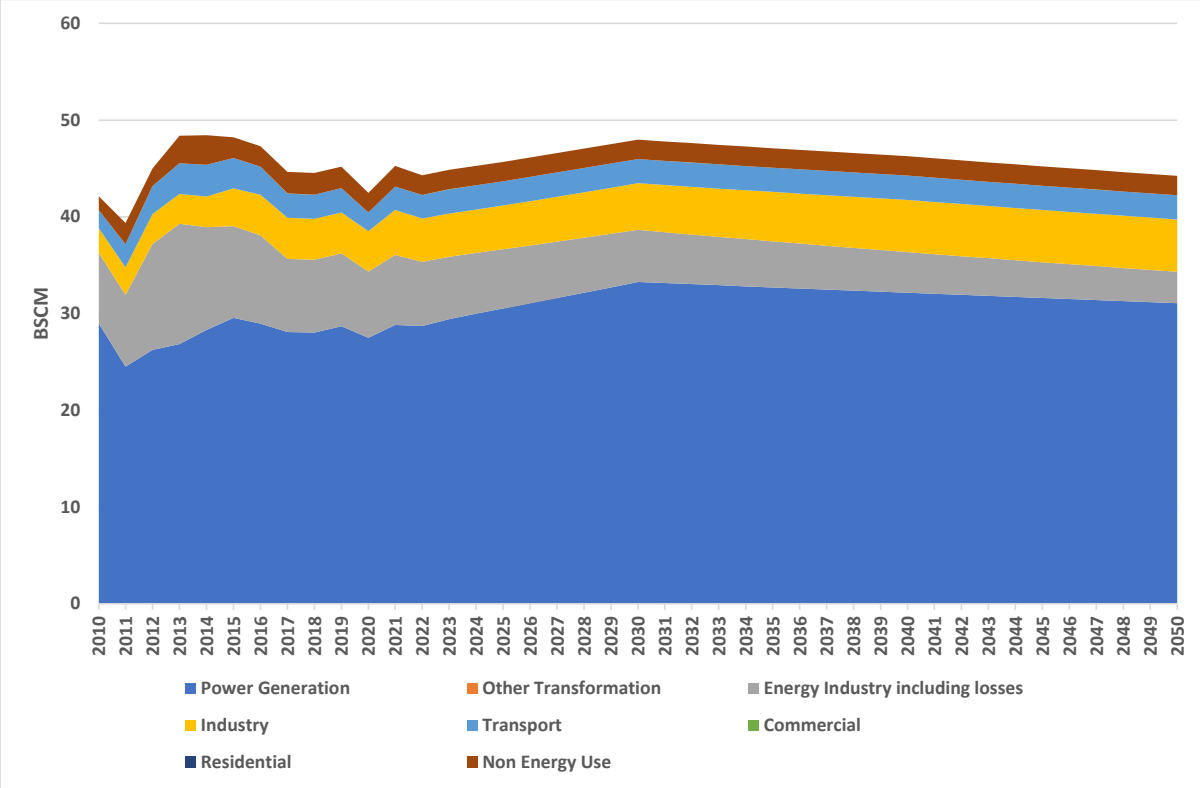
The consensus on the Industry sector would seem to be for continued growth. Thailand also has significant consumption in the Energy Industry sector. We would expect this to decline as oil and gas production declines.

Total gas demand in Thailand was around 48 bcm in 2017 of which Power was some 29 bcm. The PDP may be regarded as a high case for gas demand which would suggest total demand in 2030 of maybe 60 bcm – growth in power and industry slightly offset by reduced Energy Industry demand, and a similar level in 2040 before a decline to around 55 bcm by 2050.

APEC BAU could be considered a low case which would suggest total demand in 2030 of maybe 45 bcm falling to 40 bcm in 2040 and slightly below that by 2050. The APEC 2DC scenario suggests only a small reduction in gas demand compared to the BAU scenario.

Our Base Case demand projections and the supply and demand balances are shown in Figures 59 and 60. Demand only increases marginally before peaking in 2030 and is then in gentle decline. This is very much in line with the latest PDP discussed above and below some of the external forecasts.

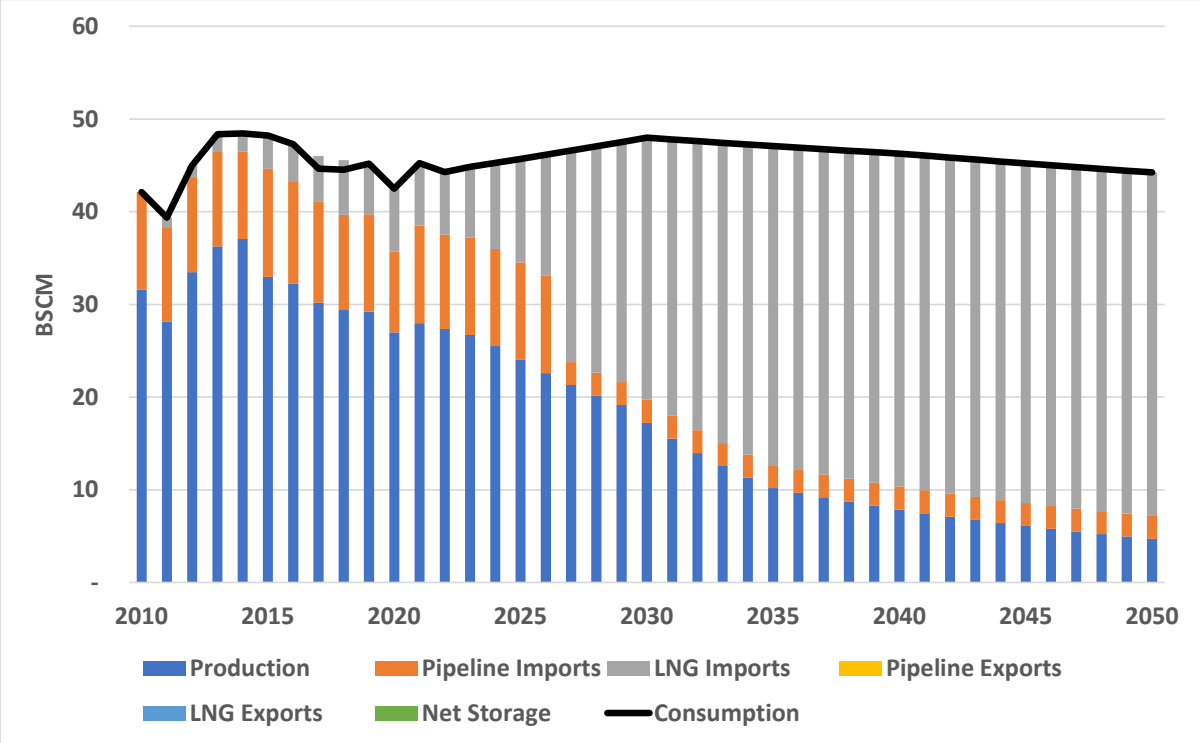
**Figure 59: Thailand Base Case Demand by Sector 2017 to 2050**




Source: IEA, OIES Estimates

With production expected to be in long run decline, and with imports from Myanmar by pipeline decreasing as contracts come to an end, this opens up the way for a significant increase in LNG imports. From around 6 bcm at the moment, LNG imports reach 28 bcm by 2030 and 35 bcm by 2040.

**Figure 60: Thailand Base Case Supply Demand 2017 to 2050**




Source: IEA, OIES Estimates, Nexant World Gas Model

## Conclusions

The power sector in Thailand is a key driver of gas demand, with industry and the transport sector having significant, but smaller volumes. There is a wide spread of possibilities for the power sector. It is generally agreed that electricity demand will increase rapidly, but how this is met is open to much more debate. The Government policy is to focus on gas and renewables as the main fuel sources, but coal currently has a 20 per cent share in power generation and, under certain scenarios, could meet much of the growth in electricity demand alongside renewables. In the base case scenario, total gas demand might rise through 2030 before declining gradually.

With gas production in Thailand expected to decline significantly over the next 30 years or so, then under the base case scenario, imports would rise sharply, especially for LNG as pipeline imports from Myanmar decline once one of the current contracts ends. Alternatively, a scenario which saw coal providing a much large share of power generation would lead to significantly lower gas demand and consequentially much lower LNG imports.

A more robust approach to decarbonisation in Thailand to achieve their COP21 targets, would seem to provide more security for gas and be little different from the base case, since coal would largely be eliminated, except where it might be abated through use of CCS.

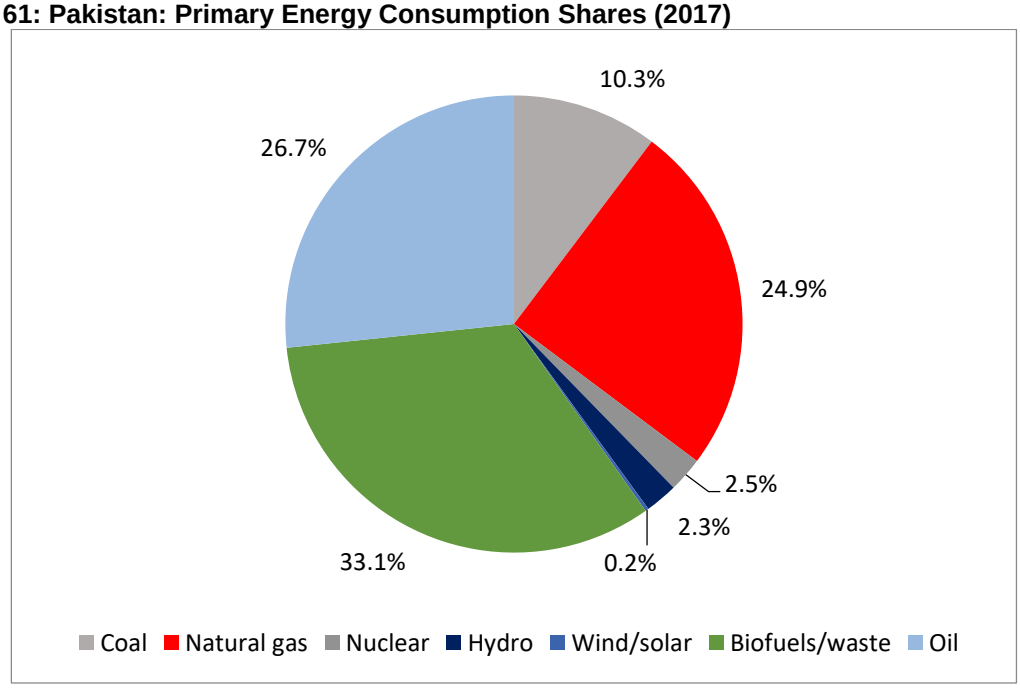
## PAKISTAN

### Historic Supply and Demand

Natural gas plays a major role in the energy matrix of Pakistan. In 1952, gas reserves estimated to be over 280 bcm were discovered in the Sui structure in Baluchistan, prompting the development of country-wide infrastructure. However, due to the mismatch between fast growing consumption and depletion of domestic reserves, the country has become an importer of LNG in 2015.

Natural gas accounted for 26.7 per cent of the primary energy consumption in 2017; and despite tremendous progress made in increasing the reach of natural gas to residential end-users, a large share of Pakistan's population relies on biomass and waste for cooking.

**Figure 61: Pakistan: Primary Energy Consumption Shares (2017)**

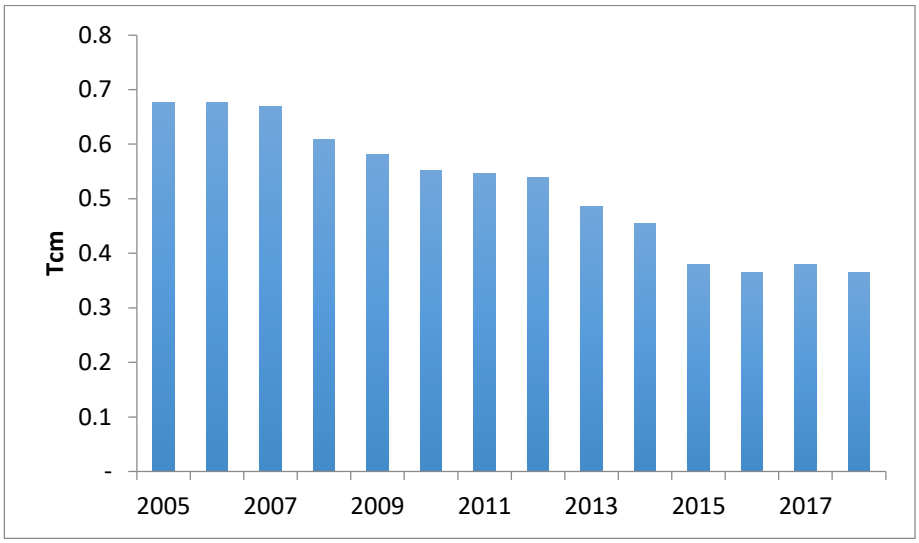



Source: IEA

Despite gas being the fuel of choice in Pakistan for industries and power generation, the dwindling domestic gas reserves and delays in the implementation of LNG and pipeline import projects have caused an increase in the consumption of coal which nearly trebled from 4.7 Mtoe in 2015 to 12.7 Mtoe in the fiscal year 2018/2019, of which 80 per cent was imported (Pakistan Ministry of Finance).

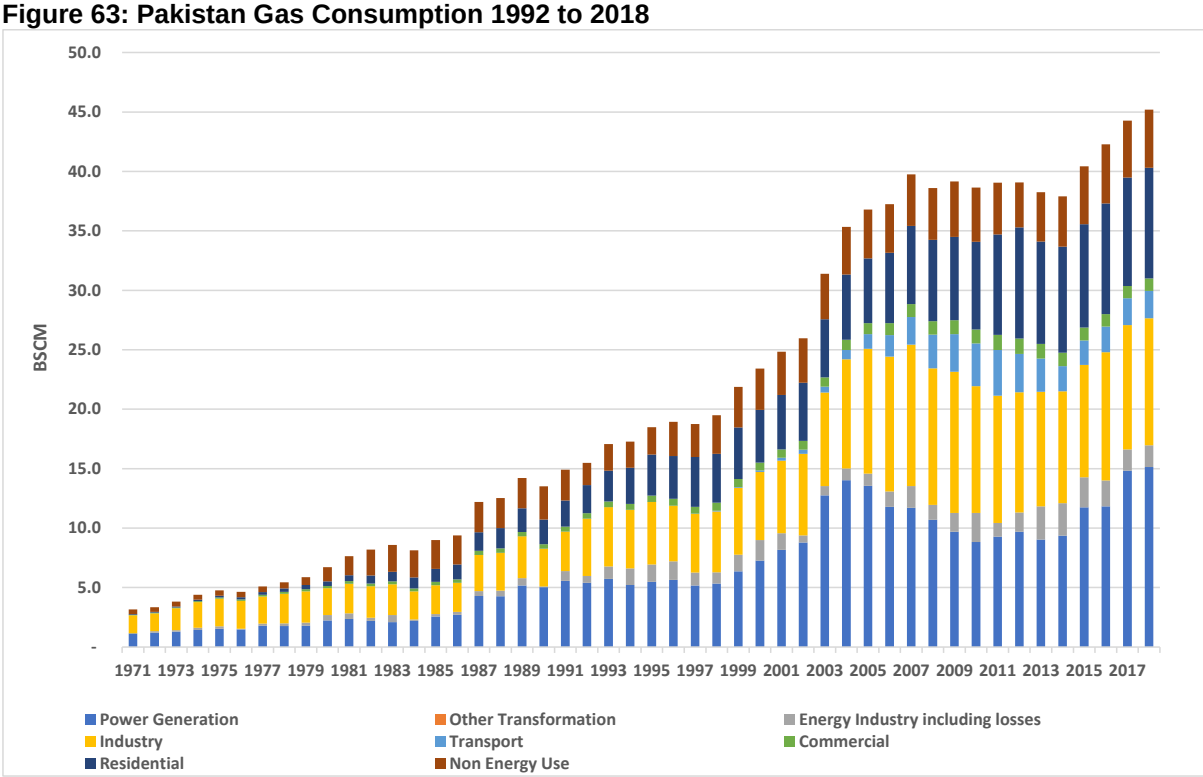
Low domestic gas prices, an unattractive fiscal regime and concerns about national security have stalled investment in upstream exploration. As a result, remaining natural gas reserves have shrunk from 0.68 tcm in 2005 to 0.37 tcm in 2018.

**Figure 62: Pakistan Natural Gas Reserves 2005 to 2018**




Source: BP

**Figure 63: Pakistan Gas Consumption 1992 to 2018**

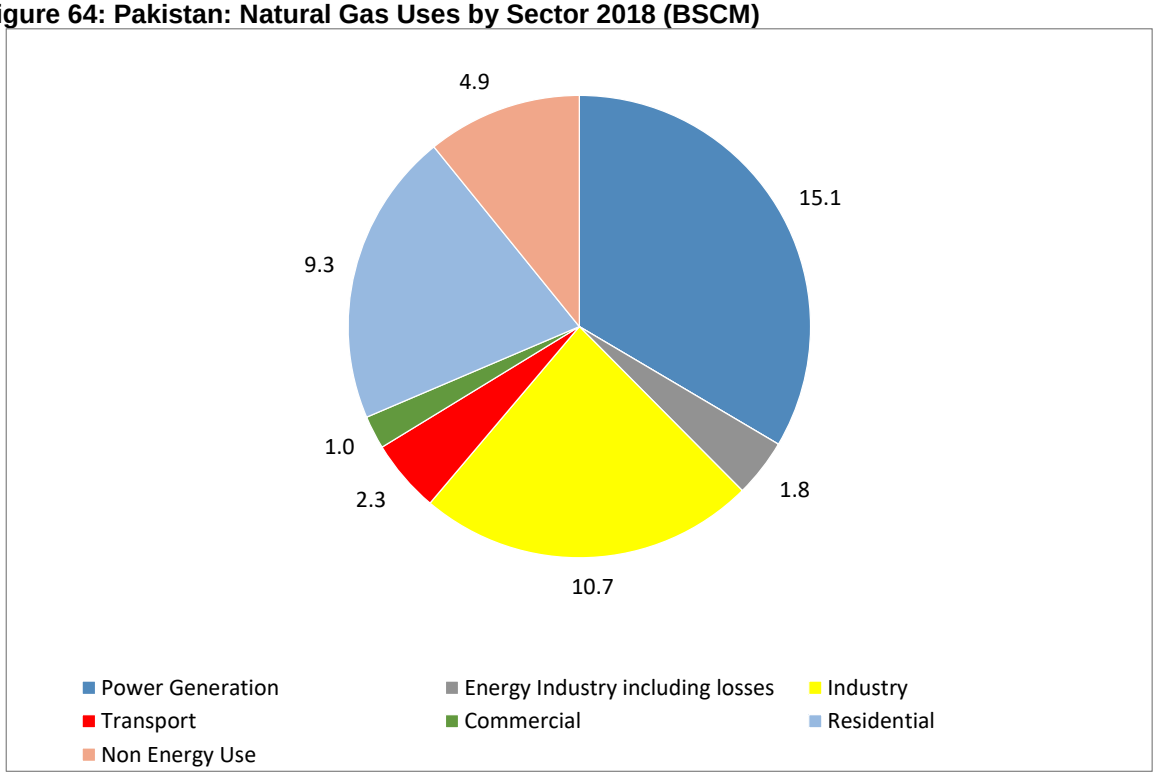



Source: IEA

In the period 1998-2004 natural gas consumption increased at an average rate of 17.5 per cent per annum, prompted by demand in the power, industrial and residential sectors, which benefited from low prices and subsidies. Gas utilisation in vehicles also increased quickly, with Pakistan leading the global growth of Natural Gas Vehicles (NGVs), second only to Iran. An imbalance in supply/demand started to show in 2004, managed initially by the government via sector gas allocation and power demand load shedding, and subsequently power supply cuts and gas shortages for the industrial and transportation sectors.

The power sector accounts for one third of the country's natural gas consumption. In contrast with other emerging markets, the residential and industry sectors also play a very important role, with 21 per cent and 23 per cent respectively. Non-energy uses (fertilizer plants) account for 12 per cent of the demand, and the industrial sector (general industry plus fertilizers) accounted for nearly 35 per cent of the total gas consumption in 2018.

**Figure 64: Pakistan: Natural Gas Uses by Sector 2018 (BSCM)**



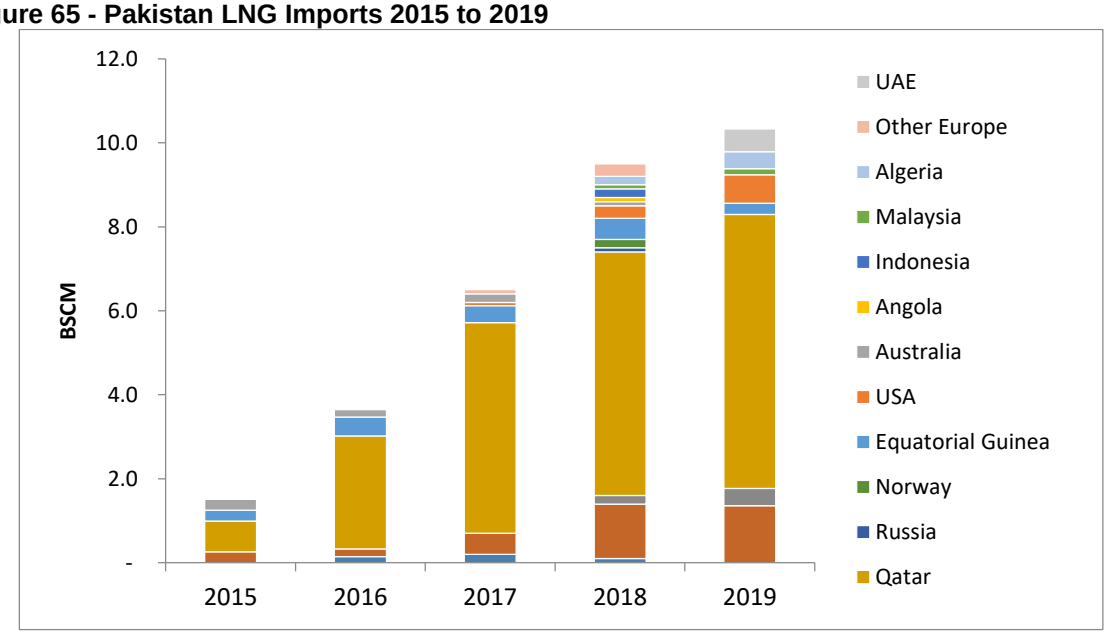

Source: IEA

In order to bridge the growing demand/supply gap, the Government of Pakistan decided to promote natural gas importing schemes. In 2005 Pakistan started conversations with LNG suppliers to allow for the construction of integrated LNG import facilities, where the government-controlled gas companies would buy regasified LNG at the exit of the terminal. This initial concept did not attract firm proposals due to market and price risks. After two failed bids, the government finally decided to promote a tolling concept, where private players would build a terminal and charge regasification fees and government entities would sign LNG supply agreements with international suppliers.

The first LNG project was commissioned in 2015, followed by a second in 2018. LNG imports reached just under 10 bcma in 2018, with a diversified list of spot and short-term supplies in addition to a 3.75 mtpa anchor contract with Qatargas.

In 2019 Pakistan imported a total of 11.1 bcm of LNG from nine countries (see Figure 65). Qatar remains the key supplier, with exports of 6.52 bcm.

**Figure 65 - Pakistan LNG Imports 2015 to 2019**



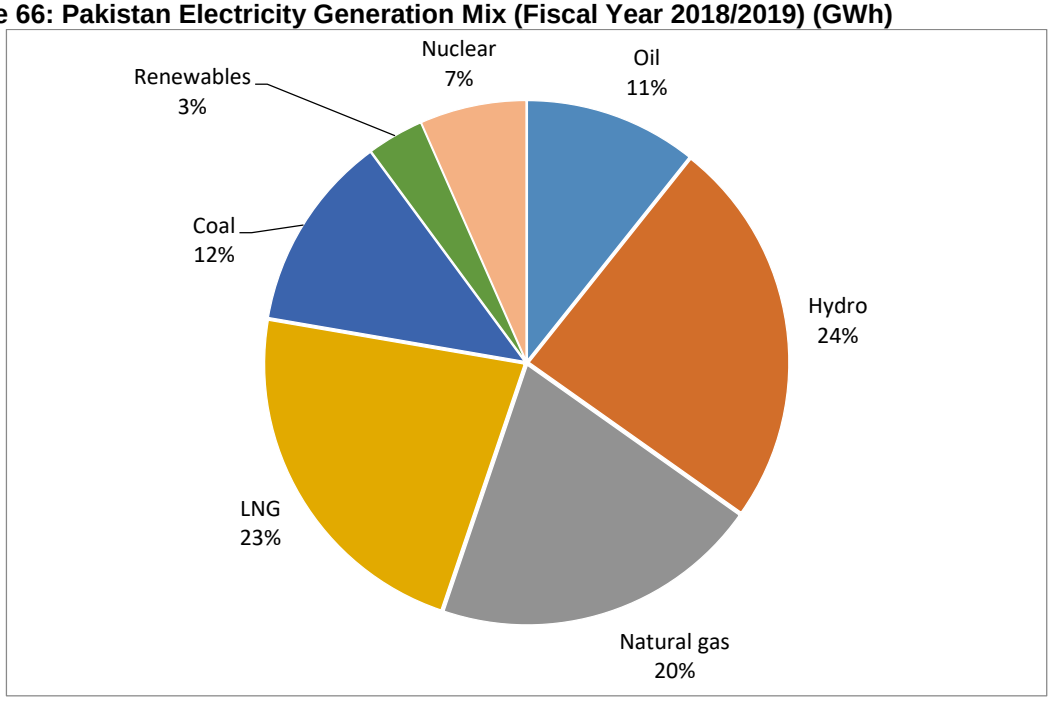

Source: IGU

## Power demand

Pakistan's electricity system has been plagued by insufficient generation capacity to meet demand from a growing population, coupled to high technical and commercial losses and high dependence on fossil fuel imports. In March 2019, the installed capacity totalled 34.2 GW against 28.4 GW in June 2017. Power generation increased 2.6 per cent from 133.6 TWh in FY 2017-2018 to 137.0 TWh in FY 2018-2019.

In FY 2018/19, piped natural gas and LNG accounted for almost 45 per cent of the electricity generation mix, with oil products (HFO and diesel) accounting for 10.7 per cent. Hydro output had been declining in earlier years due to climatic conditions and delays in the implementation of new projects, but improved in 2018-2019, with 24.2 per cent, whereas coal has jumped from less than 1 per cent in FY 2017 to 12.2 per cent due to the start of two Chinese-backed coal-fired power plants, totaling 2,563 MW.

**Figure 66: Pakistan Electricity Generation Mix (Fiscal Year 2018/2019) (GWh)**



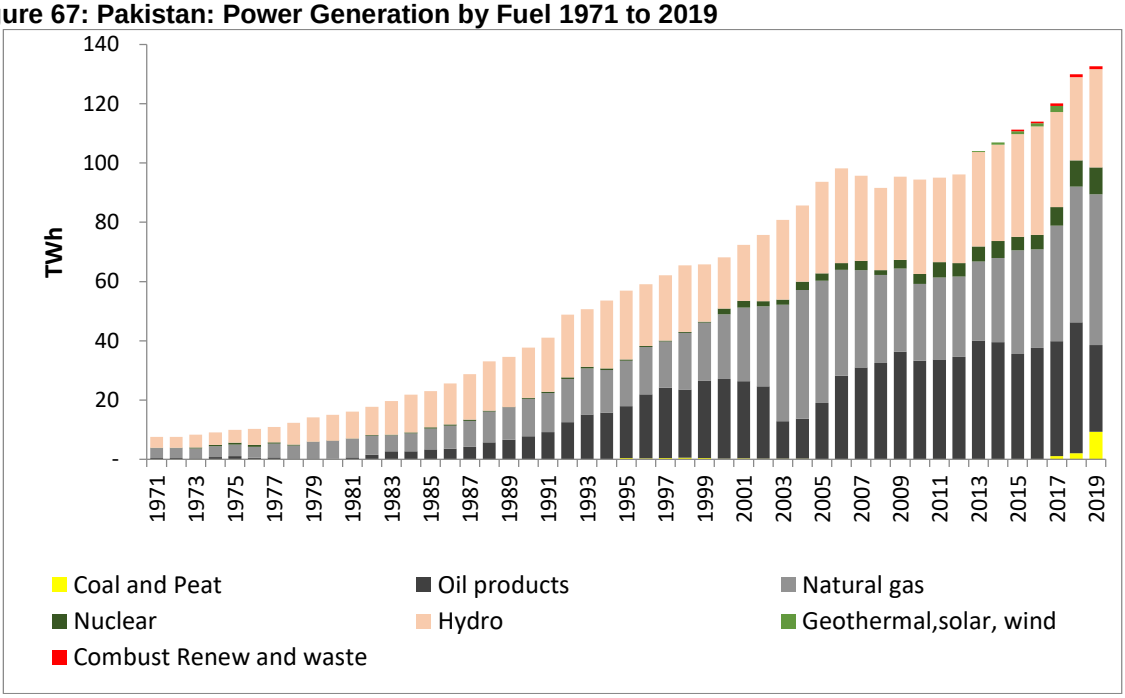

Source: Pakistan Ministry of Finance

As noted on Figure 67, the share of oil products in power generation has increased steadily since 2005. The reduction of oil in power generation represents another opportunity for increasing the share of natural gas and renewable energy, should affordable gas supplies become available as well as government policies to encourage the development of wind and solar power.

However, coal is steadily increasing its share in the electricity mix, with 1,650 MW commissioned in 2019 and another 4,590 MW in construction/development with commissioning taking place by 2021-2023.

According to the IEA, in October 2019 coal jumped to 25 per cent of the generation mix, compared to 12 per cent in October 2018. The increase was due to the addition of the new China Hub (1,320 MW) and Engro Tar (660 MW) in addition to a higher load factor. There is a significant decrease in the share of oil products, whereas natural gas accounted for circa 37 per cent of the generation mix in FY2019.

**Figure 67: Pakistan: Power Generation by Fuel 1971 to 2019**

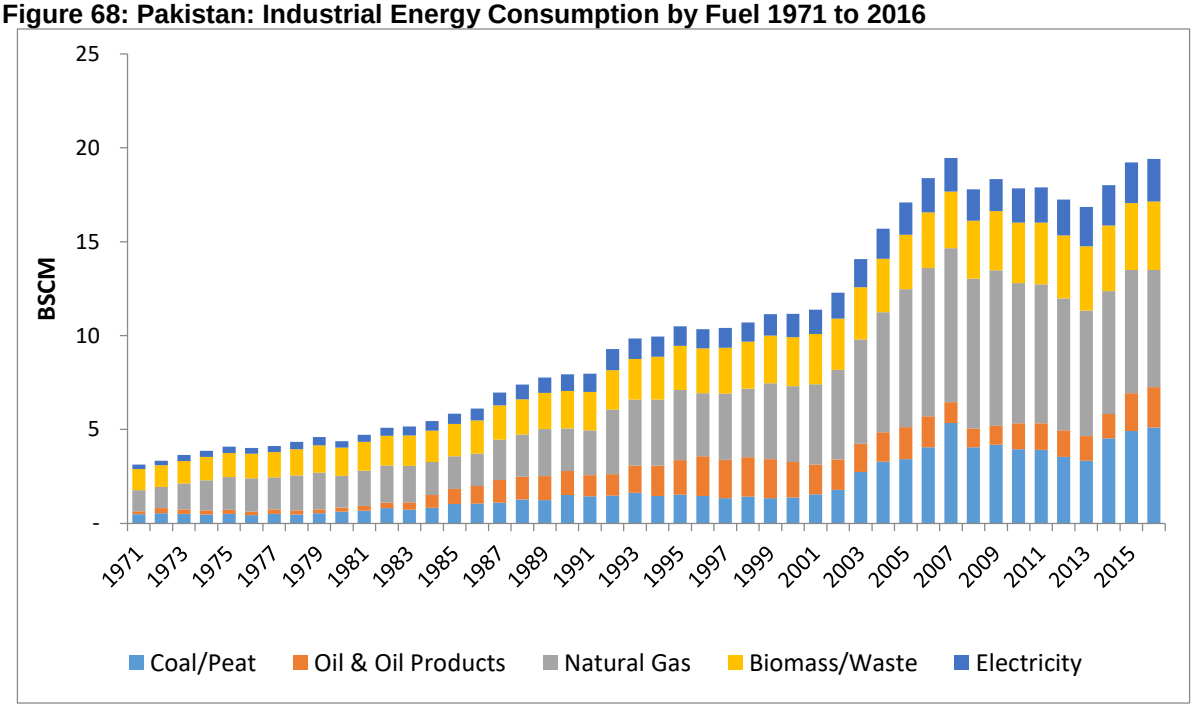



Source: IEA, NEPRA and author estimate

## Industrial Demand

Gas also plays a very significant role in the industrial sector, in particular as a feedstock in the production of fertilizers, which account for half of the total gas consumed in the industrial sector. The role of coal has been increasing since 2013, and in 2016 it represented 26 per cent of the energy consumption in the industrial sector. It is worth noting that overall, the consumption of energy in industry was negatively impacted by the world economic crisis in the period 2008-2010, Pakistan's economic recession and the shortage of domestic gas.

**Figure 68: Pakistan: Industrial Energy Consumption by Fuel 1971 to 2016**

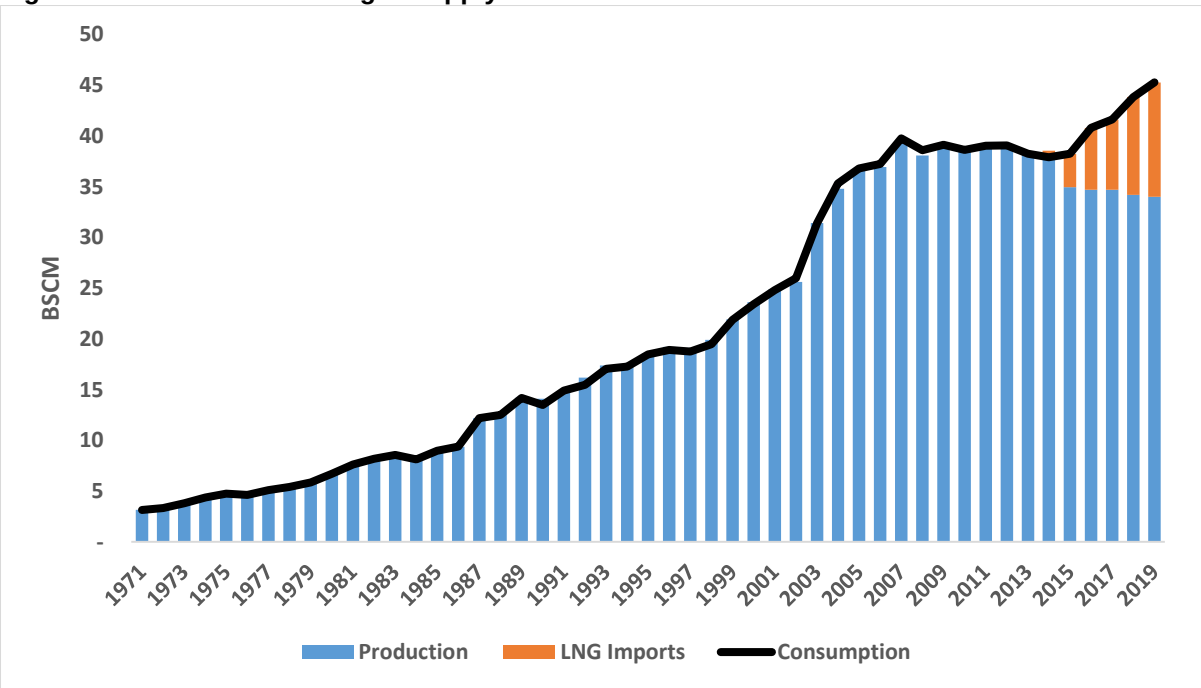



Source: IEA

Figure 68 shows that natural gas consumption was nearly stagnant in the period 2005-2014, due mostly to unavailability of supplies, and started to recover with the start of LNG imports in 2015. LNG imports nearly quadrupled in the period 2015-2019.

According to government estimates, the expected shortfall of gas supplies against unconstrained demand could reach 40 bcm by 2020, which is twice current gas consumption. The shortfall consists basically of unmet demand in the power, industrial and transport sectors, and increased usage in the residential sector, due to the expansion of distribution networks.

**Figure 69: Pakistan: Natural gas supply and demand 1971 to 2019**




Source: IEA, IGU, BP

Over the last 5 years, investment in Pakistan has been boosted by the China-Pakistan Economic Corridor, which is part of China's Belt and Road initiative. As a result, China has financed and implemented the construction of gas and coal-fired power plants in addition to targeted investment in hydro projects.

The depreciation of Pakistan's currency (Rupees) has been a significant hurdle for the import of energy commodities such as coal and LNG. As of July 5, 2019, the level of foreign exchange reserves was only USD 7.08 bn, whereas imports of crude, oil products and LNG accounted for USD 6.77 bn in the first half of 2019. As of January 2020, reserves went up to USD 12.27 bn, as a result of loans and deferred payments from China, UAE, Qatar and the IMF. Pakistan is focusing on developing indigenous resources such as renewable energy and domestic coal.

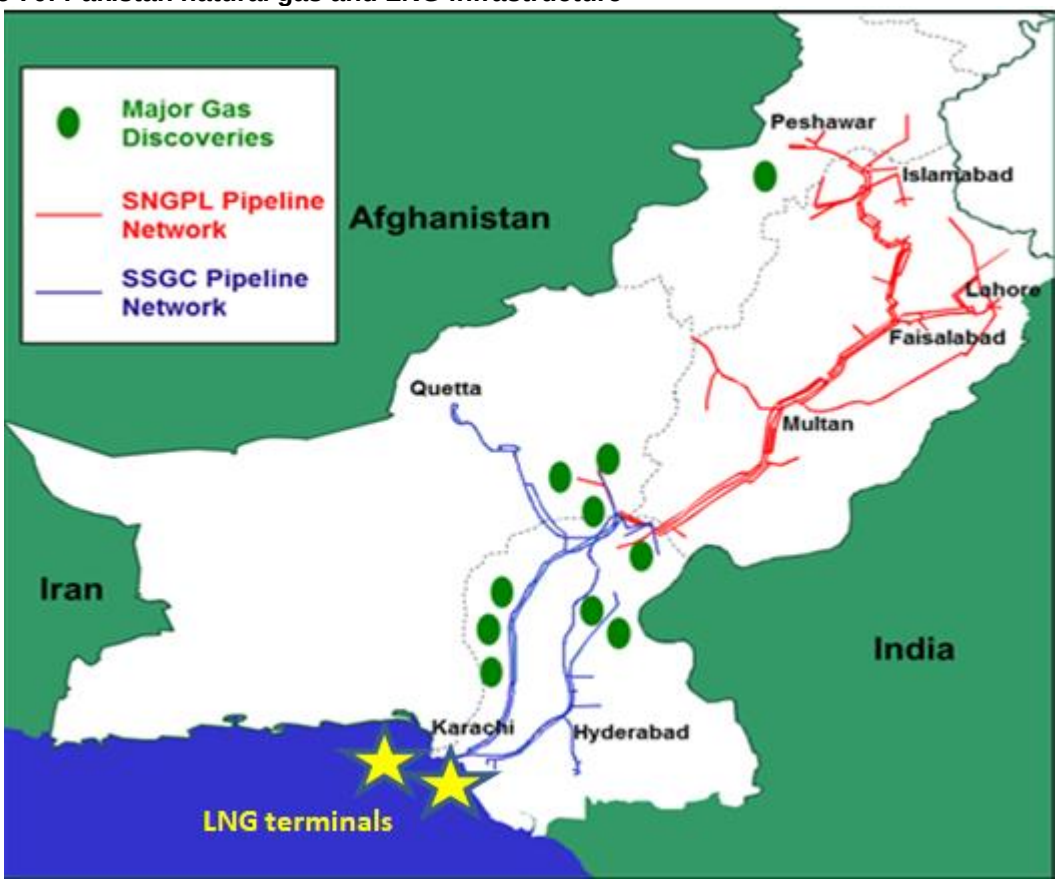
## Infrastructure and Contracts

Pakistan's domestic gas production arises largely from 42 onshore fields, mostly located in southeast and central Pakistan. There is an extensive infrastructure of pipelines connecting the gas fields to the gas utilities' networks, although there is limited connectivity between the north region, where most of the consumption is located, and the south region, where the LNG terminals have been built.

In early 2020 the Petroleum Division of the Ministry of Energy issued a tender for 18 onshore blocks, which is still ongoing. In the open bid tender for 10 blocks in November 2018, 8 blocks were awarded to local companies., To date there has been no success in finding gas offshore. Pakistan has one of Asia's most extensive gas networks, with near 13,000 Km of gas transportation pipelines and 140,000 Km of distribution lines, serving more than 9.6 million consumers across the country. The transmission

and distribution networks are operated by Pakistan's state controlled licensed gas utilities, Sui Southern (SSGCL) and Sui Northern (SNGPL) – see Figure 70. In the fiscal year 2017-2018[159] the two utilities added 678,000 new customers, and another 428,000 in July 2018-February 2019. In addition, a few gas producers have built their own independent pipelines to serve power plants and fertilizer industries.

**Figure 70: Pakistan natural gas and LNG infrastructure**




Source: SSGC, OIES

Pakistan has in excess of 3.7 million CNG vehicles, and approximately 3,400 refuelling stations. Due to the explosive growth in vehicle consumption, and the increasing gas shortage, the Government decided to implement a ban on the construction of CNG stations and licensing of Natural Gas Vehicles. The ban has been in place since 2008.

At present, there are two LNG importing terminals, both using Floating Storage and Regasification Units (FSRU), with total capacity of 9.8 mtpa.

Engro Elengy Terminal Limited (EETL) commissioned its 150,900 $m^3$ FSRU at Port Qasim, Karachi, in 2015. The Exquisite is owned and operated by Excelerate. EETL's original shareholders were VOPAK (29 per cent), Engro Corporation (51 per cent) and IFC (20 per cent). At the end of 2018 VOPAK increased its share to 44 per cent, with Engro increasing to 56 per cent. In early 2020 Engro and Excelerate announced that they will replace the existing FSRU with a new vessel, currently being built by Daewoo, which will increase the regasification capacity by 1.9 bcm. The new FSRU is expected to start operations before winter 2020. LNG is imported by the Government of Pakistan via Pakistan State Oil Company Limited (PSO). EETL provides re-gasification services and it is paid a tolling tariff.

[159] Fiscal year runs from July 1 to June 30.

The second terminal is owned and operated by Pakistan GasPort Consortium Limited (PGPC) – a wholly owned subsidiary of Pakistan GasPort Limited (PGPL), which was formed by local companies, with Trafigura owning 5 per cent. The terminal is located at Mazhar Point, Port Qasim, in Karachi. BW supplied the 170,000 $m^3$ FSRU, the Integrity. LNG is being imported by the Government of Pakistan via Pakistan LNG Limited, with PGPCL providing regasification services and charging a tolling tariff.

In July 2019 the government approved the implementation of a third LNG terminal, to be also located in Port Qasim, with capacity of 5 mtpa. So far two groups have advanced projects, but they have only been issued with provisional licenses by the regulatory authority (OGRA),

At present there are no gas imports by pipeline. The government mandated Inter State Gas Systems (Private) Limited (ISGS) to oversee the importation of gas through trans-national gas pipelines into Pakistan and make improvements in Pakistan's strategic Oil and Gas infrastructure development. So far there have been negotiations with Iran and Turkmenistan, but progress has been stalled, either due to political issues or by inconclusive viability analysis.

- Iran-Pakistan Gas Pipeline, aiming at importing gas from the South Pars field. The project comprises a 42-inch diameter 1,800 km pipeline with capacity of 7.8 bcm. The 1,150 Km Iranian section of the pipeline is being built but the 780 km section in Pakistan territory has not been started.
- Turkmenistan-Afghanistan-Pakistan-India Gas Pipeline (TAPI), Project, aiming to bring natural gas from the Yoloten, Osman and adjacent gas fields in Turkmenistan to Afghanistan, Pakistan and India. The Project consists of a 56-inch diameter 1,680 Km pipeline with capacity of 33bcma.

LNG contracts are currently held by Pakistan State Oil and Pakistan LNG Ltd.(PKLNG). Trafigura, which owns a stake in Gasport, has recently signed a 3-year LNG supply contract with ENI. Pakistan also buys LNG extensively on a spot basis.

Contracts currently in place are summarized on Table 6. All contracts are DES (Delivered ex-ship)

**Table 6: Pakistan LNG contracts**

| Seller | Buyer | Term | Volume (mtpa) |
|---|---|---|---|
| **ENI** | Trafigura | 2019-2021 | 0.36 |
| **Qatargas II T2** | PSO | 2016-2031 | 3.75 |
| **ENI** | PLTL | 2017-2032 | 0.75 |
| **Gunvor** | PLTL | 2017-2022 | 12 cargoes/year |
| **PERTAMINA** | PLTL | 2018-2028 | 1.5 |

Source: GIIGNL, Natural Gas Daily

## Government Policy and Regulation

The Ministry of Energy (Petroleum Division) mission statement is to ensure availability and security of a sustainable supply of oil and gas for economic development and strategic requirements of Pakistan and to coordinate development of natural resources of energy and minerals.

The Ministry's Directorate of Gas, oversees the following activities:

- Formulation of the Government Policies regarding Natural Gas, Liquefied Petroleum Gas (LPG), Liquefied Natural Gas (LNG), Compressed Natural Gas (CNG).
- Assessment and management of gas demand & supply.

- Allocation of gas from new finds to gas utility companies;
- Allocation of Natural Gas from different supply sources to various sectors;
- Review and execution of gas price agreements with producers and gas sales agreements between the producers and the Government nominated buyer;

The Ministry organizes auctions for concessions (onshore) and production sharing contracts (offshore). Wellhead gas prices are linked to oil prices under several sets of price policies. Producers are allowed to export volumes exceeding proven national proven reserves and supply commitment, subject to a windfall price levy.

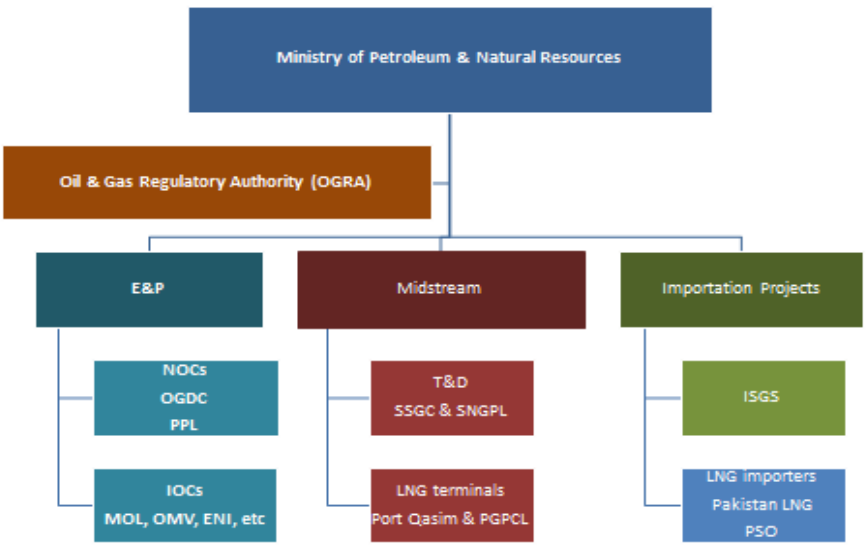
According to the latest available 2012 Policy, the well head price for Associated or Non-Associated Gas will be indexed to the C&F price of a basket of Arabian/Persian crude oil imported in Pakistan. In practical terms, after applying all discounts the price is capped at an oil price of USD 34.2 – 37.6/bbl onshore and USD 39.9-51.6/bbl offshore.

The Oil and Gas Regulatory Authority (OGRA) regulates mid- and downstream gas, oil and LPG activities. Among others it has the following powers:

- Exclusive power to grant, amend or revoke licences for regulated activities and enforce compliance of licence conditions;
- Determine in consultation with the Federal Government and the licensees, a reasonable rate of return to the natural gas licensees;
- Determine the revenue requirement of gas utilities covering the cost of gas, transmission and distribution cost and the prescribed return;
- Develop and enforce performance and service standards;
- Prescribe procedures and standards for investment programmes of the gas utilities and oversee their capital expenditure;
- Oversee the construction, operation and marketing CNG, LNG, LPG, gas storage and mid/downstream oil products facilities.

Third party access rules and the pipeline network codes are being improved to enable new players to take part in the commercialisation and shipping of natural gas.

**Figure 71: Pakistan: Structure of the Gas Industry**




Sources: Pakistan Ministry of Petroleum & Natural Resources, SSGC, SNGPL, OIES

The current LNG Policy allows for the following types of project structure: a) integrated projects, in which the terminal developer arranges LNG imports as well as its own buyers and b) unbundled in which the terminal developer, LNG importer and LNG buyers are different.

The power sector is regulated by the National Electricity Regulatory Authority (NEPRA), which authorizes licenses to power generators, approve distribution tariffs and determine the cost of fuel for thermal power plants.

## Supply and Demand Projections

### External Demand Projections

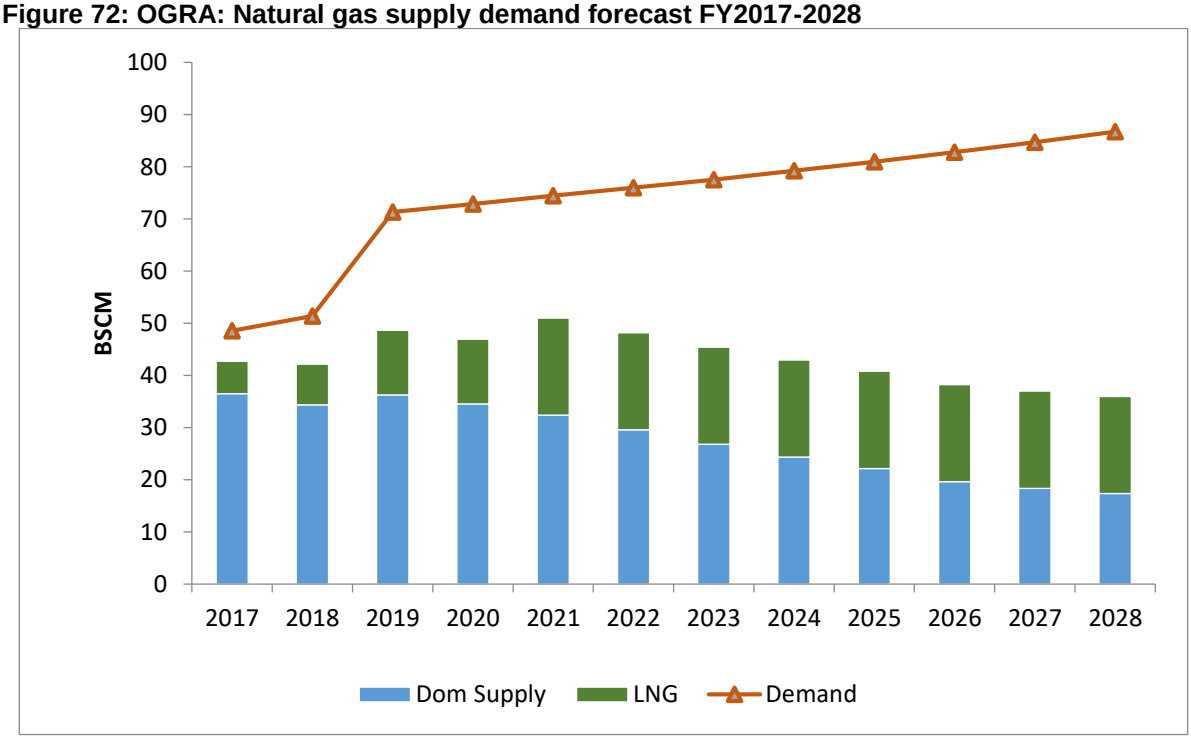
#### *Oil and Gas Regulatory Authority (OGRA) Supply Demand Forecast (2017-2028)*[160]

The latest gas supply and demand outlook, published by OGRA, forecasts Pakistan's unconstrained gas demand, with an average growth of 5.41 per cent in the period FY2017-2028. The actual lower gas consumption figures in FY2017 and 2018 reflect the constraint in supplies, which were later boosted with the commissioning of the second LNG terminal in 2018.

OGRA's supply figures already comprise the commissioning of a third LNG terminal in FY2021. OGRA's unconstrained demand forecast shows a huge gap of 51 BSCM by FY2028, which could only be partially addressed by the construction of a 4th LNG terminal plus the Turkmenistan-Afghanistan-Pakistan-India pipeline (TAPI, 13.7 BSCM) and Iran-Pakistan pipeline (IP, 7.75 BSCM). The pipeline projects might take decades to be built for geopolitical and economic reasons, whereas a 4th LNG terminal might be difficult to accommodate in the busy Port Qasim/Karachi Port.

By 2024, LNG will represent 43 per cent of total gas supplies. Increased dependence on imported gas will also have a deleterious impact on the foreign exchange account, particularly if LNG prices recover post 2023.

**Figure 72: OGRA: Natural gas supply demand forecast FY2017-2028**

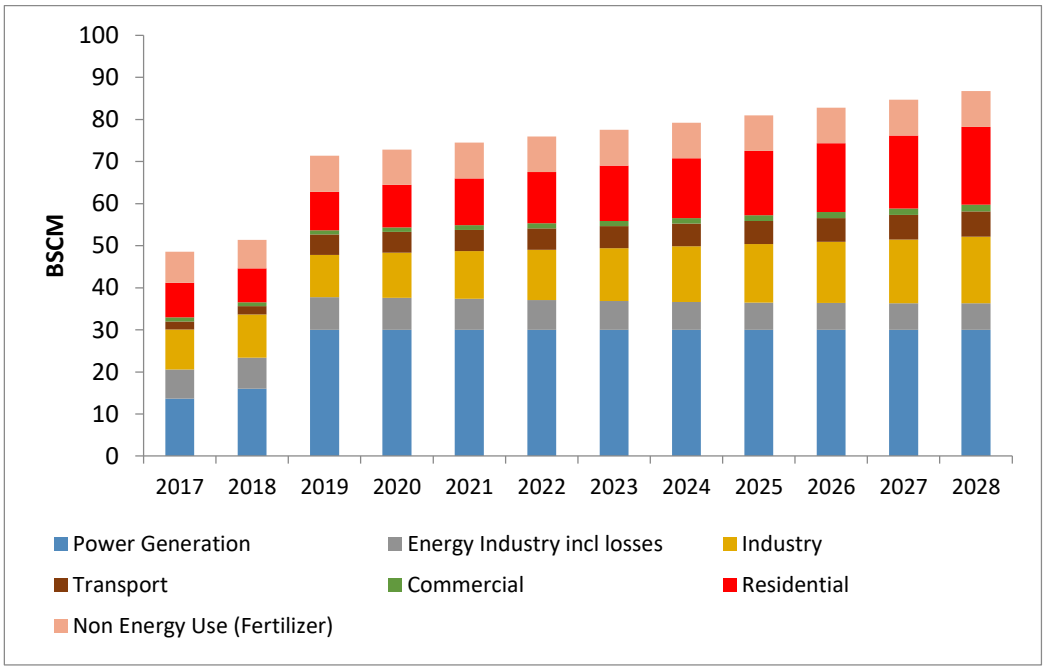



Source: OGRA 2018

[160] State of the Regulated Petroleum Industry 2017-2018 (Pakistan Fiscal Year runs from July 1 to June 30)

According to OGRA's projections, the largest contributor to future demand is the power sector, with consumption growing from 19.94 bcm in FY2018 to 34.57 bcm in FY2019[161], due to the expected commissioning of 3,750 MW of new gas-fired plants. The projections also seem to include the unlikely conversion to gas of all oil-fired plants (6.8 GW). From FY2022 onwards there is no increase in power capacity, except for captive power, whose supply could also be replaced by oil/diesel generators, in case of further gas shortage. Industrial demand is led by fertilizer and cement plants, but consumption growth in these segments also stalls after 2020.

**Figure 73: Pakistan: Natural gas demand forecast by sector (OGRA) FY2017-2028[162]**




Source: OGRA 2018

### *National Electric Power Regulatory Authority (NEPRA) Projections*

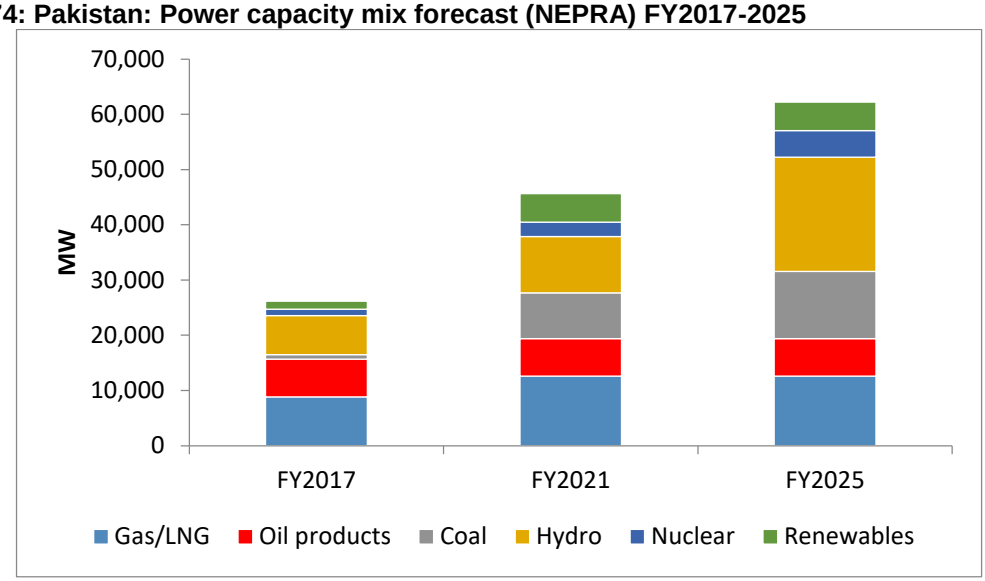
NEPRA has produced a forecast of power supply and installed capacity until FY2025[163]. They show an increase in gas-fired capacity from 8,868 MW in FY2017 to 12,626 MW in FY2021. There is no further increase in gas capacity until FY2025. Coal is a big winner, growing from 810 MW in FY2017 to 12,163 MW in FY2025. There is no increase in oil-fired power capacity.

NEPRA estimates a big leap in hydro, with capacity increasing from 7,116 MW in FY2017 to 20,676 MW in FY2025. However, they also warn that it is highly likely that hydro projects will be delayed. Other renewable energy capacity is expected to treble, growing from 1,465 MW in FY2017 to 5,153 MW in FY2025.

This is already a constrained scenario for gas- and oil-fired generation, with the aim of encouraging domestic energy resources, such as renewable energy and domestic coal.

[161] Figures include captive power demand and power generation plants
[162] Industrial demand includes general industry, fertilizers ( non-energy uses) and cement
[163] State of the Industry Report 2017

**Figure 74: Pakistan: Power capacity mix forecast (NEPRA) FY2017-2025**




Source: NEPRA

### *Conclusions on Demand*

OGRA and NEPRA's forecasts are complementary, but the OGRA unconstrained scenario (74.5 bcm in 2021 in 2021 and 86.7 bcm in 2028) seems over-optimistic. In the unconstrained demand scenario power consumption grows on average 8.2 per cent/year from 2018 to 2028, whereas residential demand grows on average 8.7 per cent/year in the same period. In the unconstrained demand scenario, Pakistan would need to import an additional 50.8 bcma by 2028.

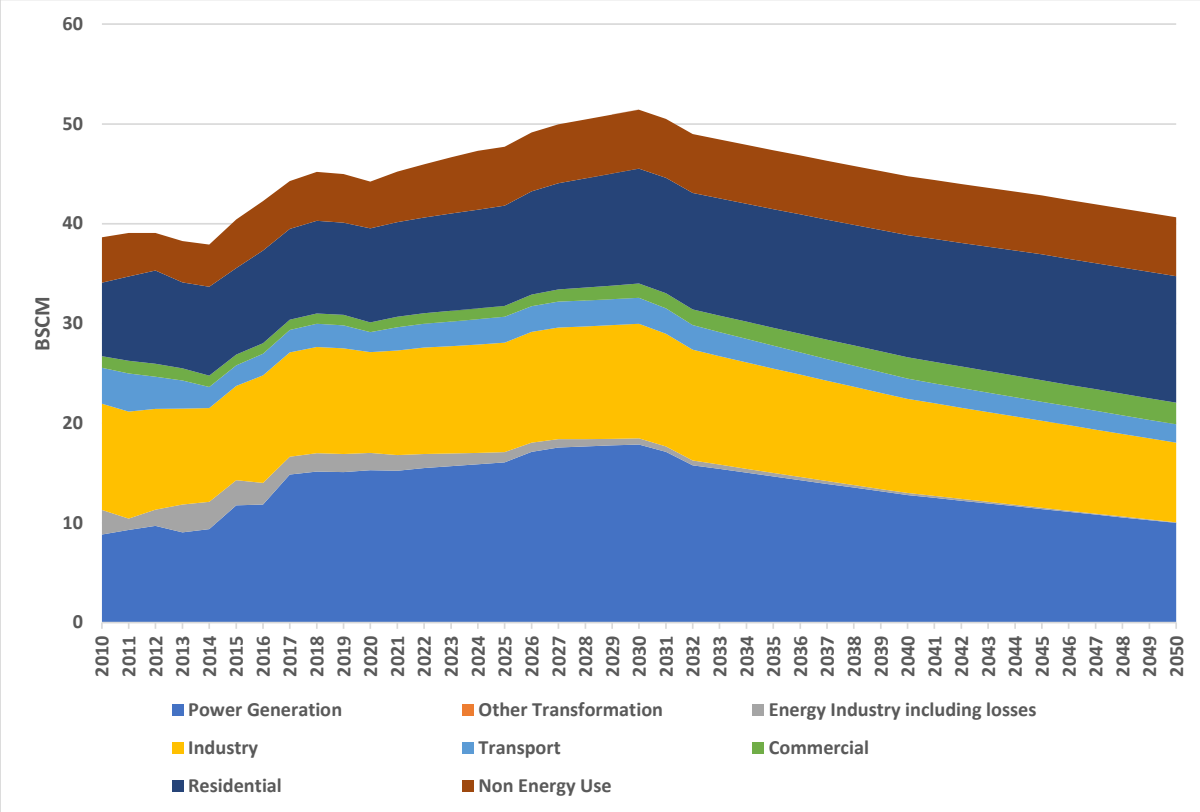
Unless there is a breakthrough in exploring for and developing domestic gas resources, the gap could only be filled by imports. However below cost domestic end-user prices, coupled to the limitation in providing government guarantees for importing LNG and the depletion of foreign reserves could be a deterrent to the development of new import schemes. The existing LNG terminals rely on government entities procuring and contracting LNG but it is that this scheme would be replicated for a third and fourth terminals.

Therefore, a substantial part of the unconstrained demand for gas would be unmet; the most likely outcome is for the government to manage demand by increasing gas prices to industrial consumers and by curtailing supplies to power plants, industry and NGVs. Consumption in the residential sector will continue to grow, albeit more moderately than in OGRA's scenario, due to low end-user prices and the fact that SNGPL and SSGCL are remunerated via a 17 per cent return on assets, which encourages both companies to continue laying pipelines and connecting new customers.

## Gas Supply and Demand Balance

Figure 75 summarizes the demand forecast by segment. Power demand includes the optimization of the existing gas/oil fired plants and the commissioning of a 1,236 MW of gas fired power plant in 2021, but with supplies to plants reduced in line with reduced availability by 2025. Industrial consumption grows by 4.3 per cent/year on average to 2030, but is then curtailed subsequently by reduced supply availability. In this scenario, coal might play a bigger role, depending on the economics of extracting domestic coal from the Thar basin. In summary, gas demand is managed downwards through interventions in the power, industrial and NGV segments. If pipeline supplies do not materialize by 2030, then demand would need to be further managed, unless there is a decision to build a large onshore LNG terminal.

**Figure 75: Pakistan Base Case Demand Projection**



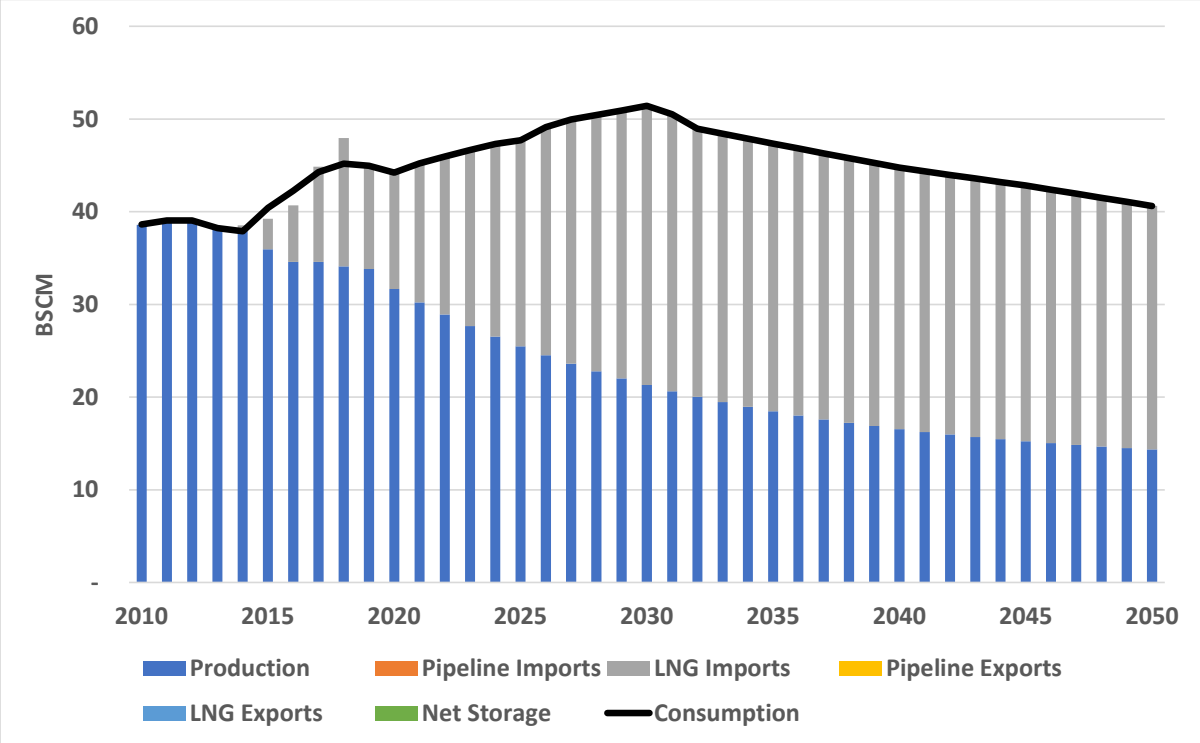

Source; IEA, OIES Estimates, Nexant World Gas Model

Our Base Case supply and demand balance is shown in Figure 76. In this scenario, LNG supply increases by the commissioning of a third terminal in 2022-2023 and a fourth terminal after 2025, followed by an upgrade of the existing terminals, adding 3.1bcm of send-out capacity for the first 3 terminals. Pipeline imports from Iran or Turkmenistan would only materialize around 2030, otherwise the gap would need to be met either by additional LNG reports or demand curtailment.

The Base Case Scenario uses depletion figures provided by OGRA for domestic gas supplies. LNG supply might be constrained to three/four terminals, due to port congestion/dredging issues, pipeline infrastructure bottlenecks [164], price affordability and Pakistan's dwindling foreign reserves. Gas consumption is predicted to grow to 51.11 bcm by 2030, but then it starts to decrease until in 2050 it drops to the same level as in 2017, approximately 42.3 bcm. In this scenario, gas demand is managed via reduced consumption for power, industry and vehicles, in tandem with available supplies.

[164] https://www.argusmedia.com/en/news/1735490-pakistans-lng-import-growth-cut-by-power-constraints

**Figure 76: Pakistan: Base Case Supply Demand Projection**




Source; IEA, OIES Estimates, Nexant World Gas Model

## Conclusions

Although there is potential for gas consumption to grow to nearly 87 bcm by 2030, this is unlikely to happen, because there is no prospect for a substantial increase in gas production. The discoveries in onshore Pakistan are not large and the offshore exploration efforts have not been successful. Although LNG is a possible alternative, it is also unlikely that Pakistan will be importing volumes of 40-50 bcm because the government might not be in a position to purchase or provide guarantees in hard currency for such volumes.

Despite lower international LNG prices in 2020, Pakistan is already is cutting down imports, in the wake of the COVID19 pandemic, which by April 2020 caused a reduction in gas demand of 30-50 per cent. Therefore, the demand projections for 2020 are unlikely to materialize as above.

Higher LNG prices will require deeper price reforms. The 2018 price hike of 35 per cent, on average, helped to alleviate the burden caused by LNG imports, but end-user prices are mostly set below cost of supply.

The international pipelines linking Pakistan to Iran and Turkmenistan are also unlikely to materialize before 2030, due to economic sanctions and the large finance requirement.

Renewable energy is an alternative for the energy sector, but the government indicative planning forecasts are relatively modest, circa 11 per cent share by 2030.

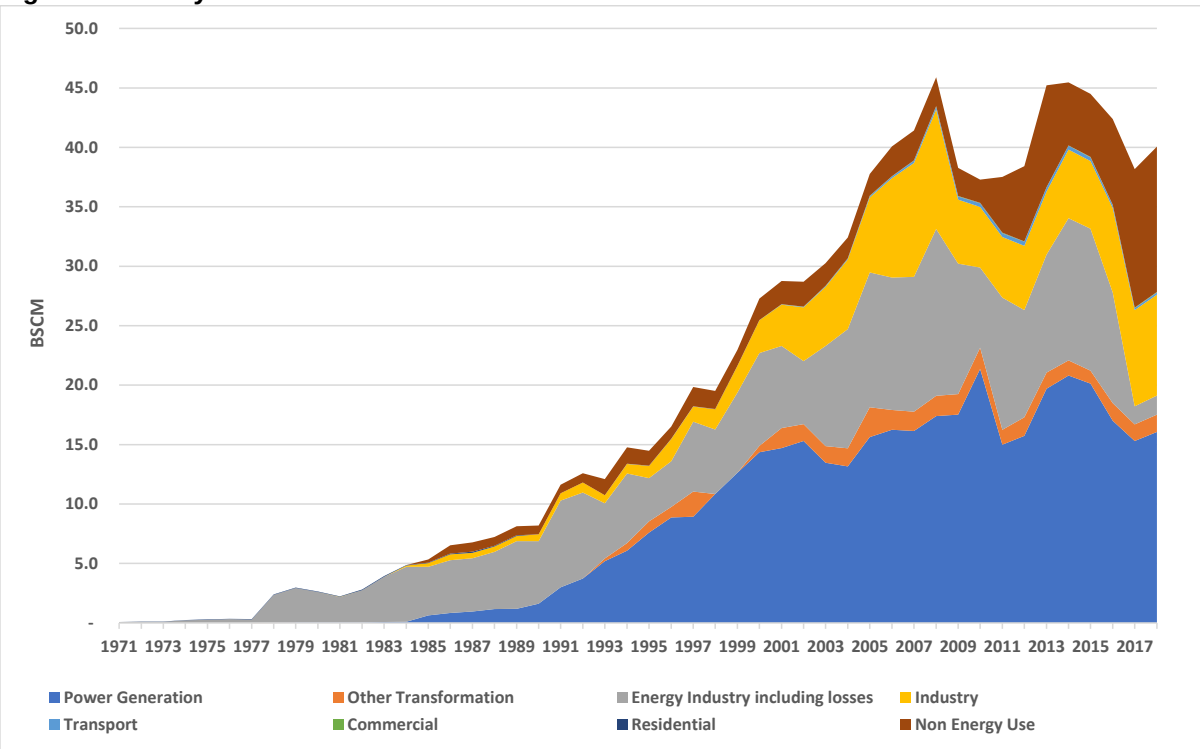
Unless there is a significant increase in domestic gas production, gas demand will stay in the range of 32 to 42 bcm by 2050, for the Base and Decarbonisation cases. Demand will continue to be managed up and downwards to meet supply availability. Renewable energy is expected to grow by 15 per cent per annum if the government puts in place an appropriate regulatory and pricing framework.

# MALAYSIA

## Historic Supply and Demand

Malaysia began consuming natural gas in the early 1970s, mostly in connection with the development of its oil industry. Consumption of gas in industry began in the late 1970s, and for power generation in the mid-1980s, but did not grow strongly until the 1990s. Recently there has been increased use of gas as a feedstock in the petrochemicals industry.

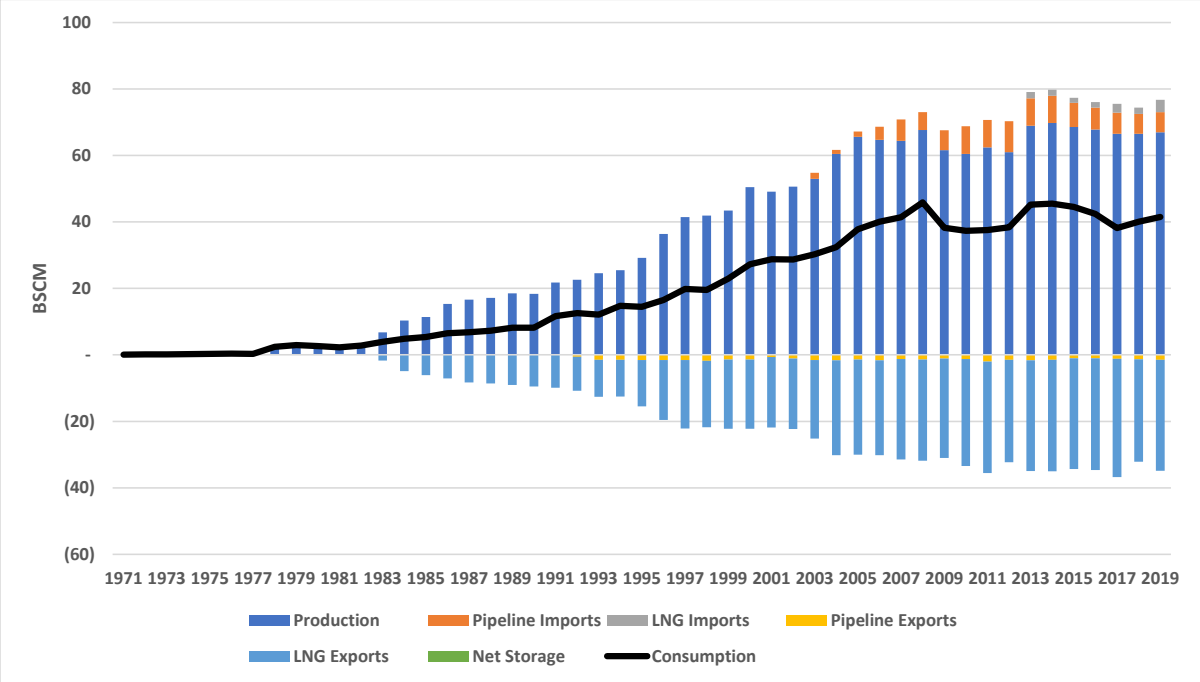
**Figure 77: Malaysia Gas Demand 1971 to 2018**




Source: IEA

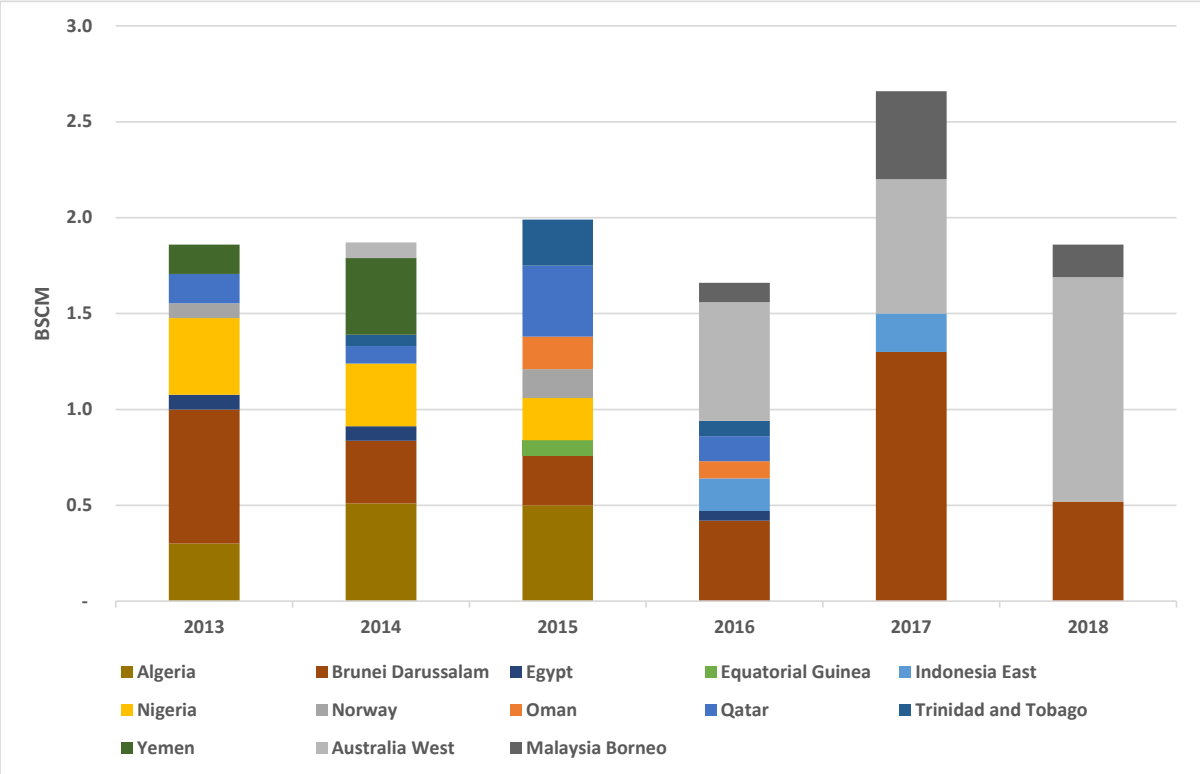
The gas industry developed on the back of domestic production, with the growing volumes leading to the development of LNG exports in the 1980s from Bintulu in Borneo, with some small pipeline exports to Singapore beginning in 1992. Pipeline imports from Indonesia began in 2003, from Sumatra and then also the West Natuna field. LNG imports began in 2013 as the decline in production in Malaysia Peninsular region led to increasing shortages of gas.

**Figure 78: Malaysia Supply Demand Balance 1971 to 2019**




Source: IEA

**Figure 79: Malaysia LNG Imports 2013 to 2018**

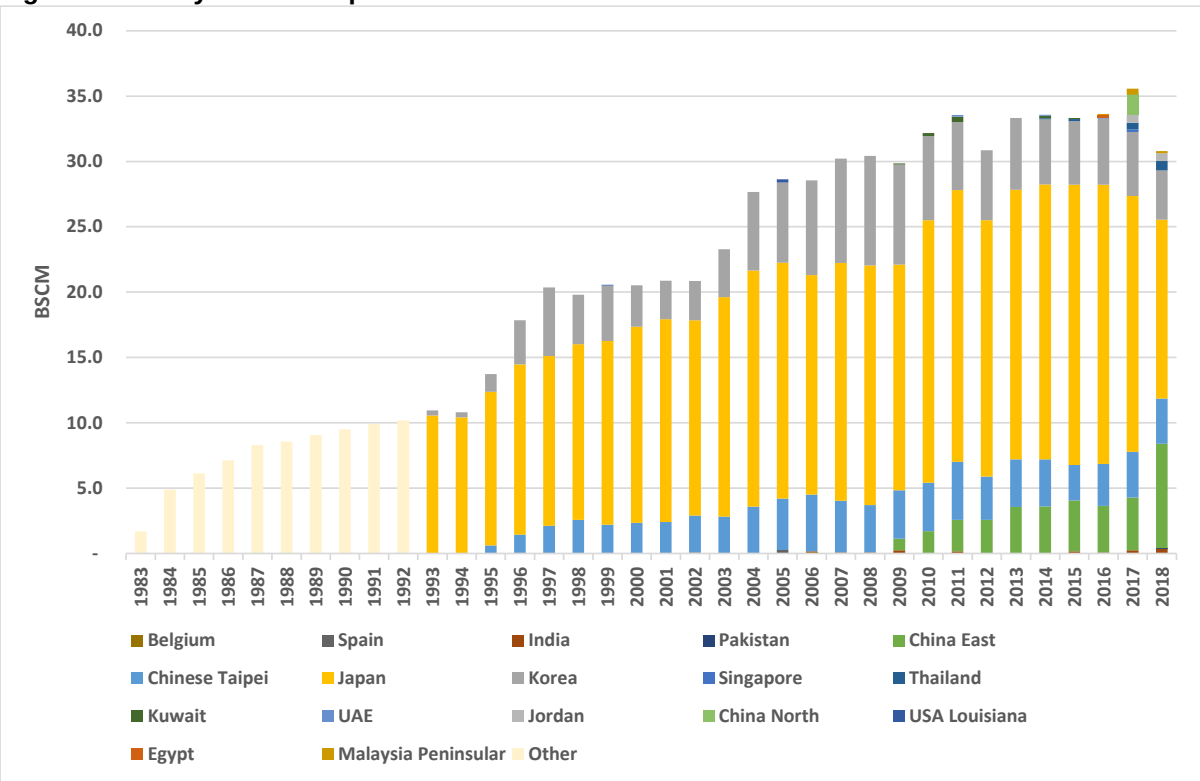



Source: IEA

Petronas has been responsible for purchasing the LNG, initially under short term contracts or spot, from a variety of sources, but also longer-term contracts with the Gladstone terminal in Australia and Qatar. The pipeline contract with Indonesia expires in 2020.

Malaysia is more heavily involved in the export side of the LNG market, with Japan being the main buyer for a long time, with Korea and Chinese Taipei also taking increasing volumes, and more recently China.

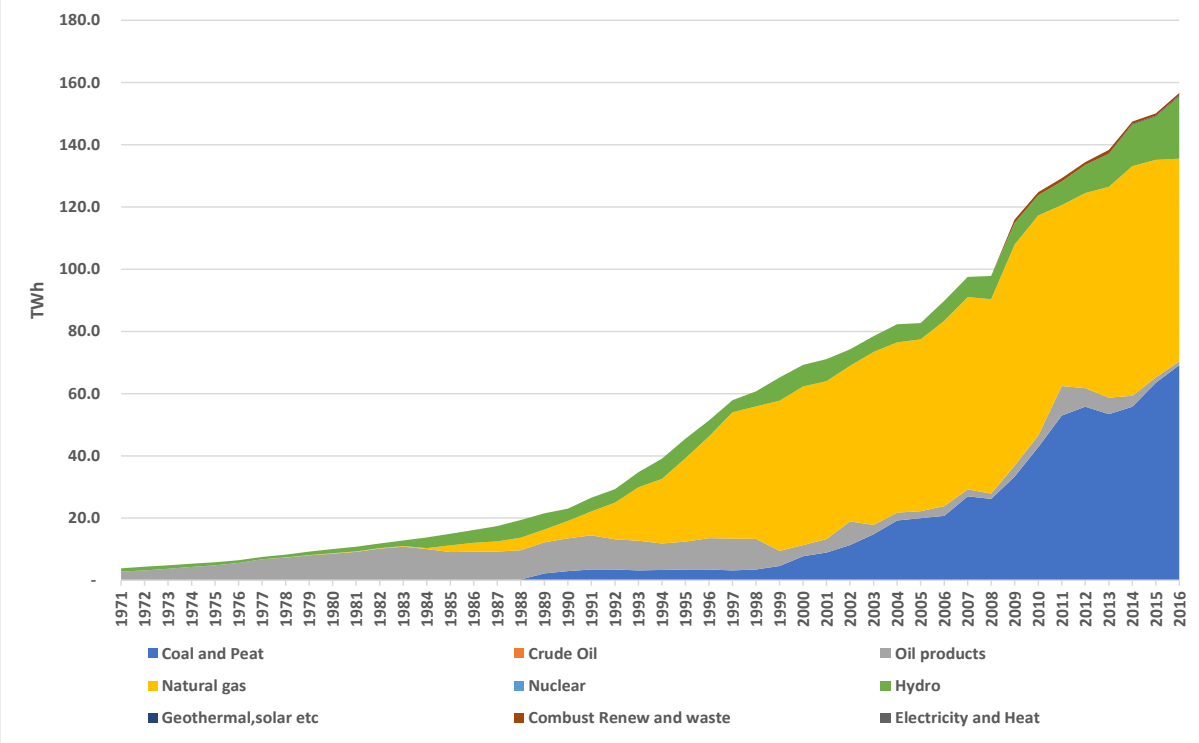
**Figure 80: Malaysia LNG Exports 1983 to 2018**




Source: IEA

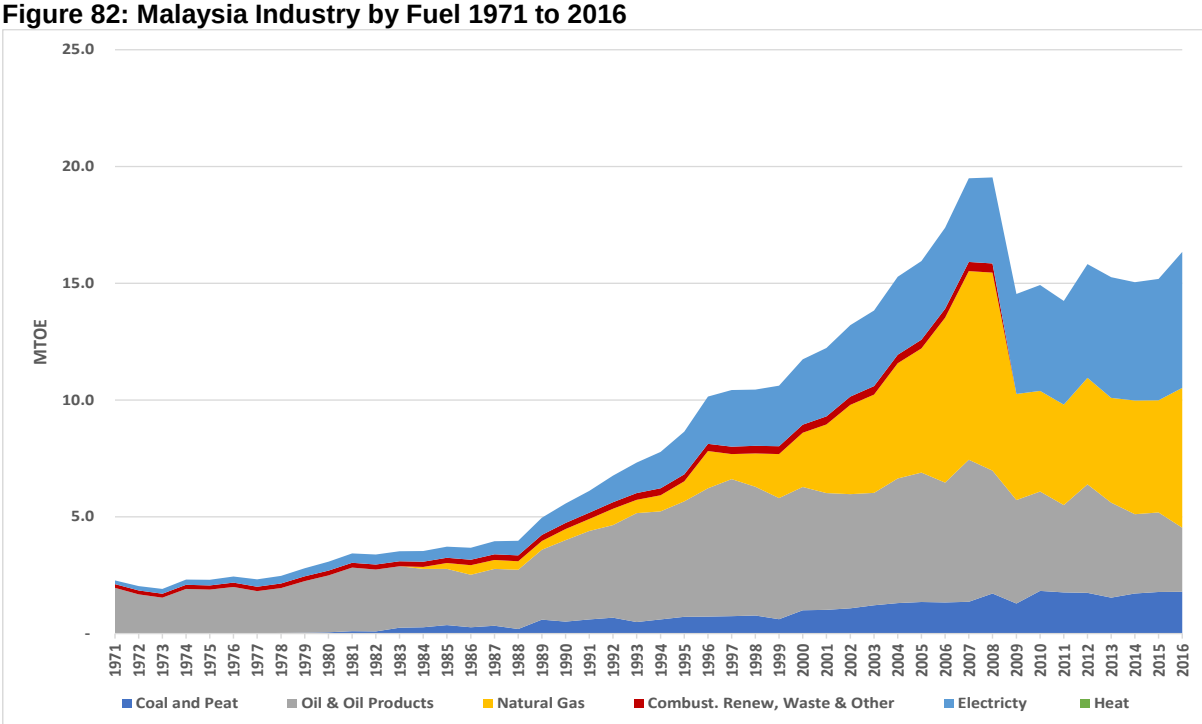
Power generation was almost all oil-fired in the 1970s with very small amounts of hydro. The development of natural gas drove the expansion of power generation, eventually largely displacing oil. Coal generation then provided much of the generation growth from the early 2000s, with some additional hydro. Biofuels and solar have only just started to make inroads into the mix. Coal generation now matches natural gas in the generation mix.

**Figure 81: Malaysia Power Generation by Fuel 1971 to 2016**




Source: IEA

**Figure 82: Malaysia Industry by Fuel 1971 to 2016**




Source: IEA

Oil products have been a key fuel for industry but natural gas provided much of the growth from the late 1990s. The sharp drop in 2009 may, in part, have reflected some reclassification to other sectors as well as a decline due to the global recession, and rising gas use. Coal has recently been making some inroads into the industry sector.

## Production

Total proved gas reserves in the ASEAN countries were about 7.5 trillion cubic meters in 2018; Malaysia had the second largest reserves at 2.4 tcm (33 years of current production) only exceeded by Indonesia with 2.8 tcm[165]. PETRONAS has been sourcing gas from the Malaysia-Vietnam Commercial Arrangement Area (CAA) since 2003 and the Malaysia-Thailand Joint Development Area (JDA) since 2005. Piped gas from CAA and imports from Indonesia's Natuna are processed at the PETRONAS Gas Berhad's gas processing plants (GPPs) together with domestic gas produced offshore Peninsular Malaysia[166].

The Malaysia-Thailand Joint Development Area (MTJDA) is located in the lower part of the Gulf of Thailand and the northern part of the Malay Basin. The area is divided into three blocks, A-18, B-17, and C-19, and is administered by the Malaysia-Thailand Joint Authority (MTJA), with each country owning 50 per cent of the MTJDA's hydrocarbon resources. According to the MTJA, 27 natural gas fields were designated by 2014, including nine fields each in Block A-18, Blocks B-17 and C-19. Production at Block A-18 started in 2005 and has a contracted level of about 8 bcm/year of processed natural gas. Block B-17 and Block C-19 came online by 2010. From 2010 to 2026, Blocks B-17 and C-19 are contracted to deliver 3.4 bcm/year for the first 10 years then 2.5 bcm/year for the remaining 6 years. Overall, average natural gas production from MTJDA was slightly higher than 11 bcm in each of 2015 and 2016. Block B-17-01 is expecting development of its gas fields in 2017, with first gas deliveries in 2018 MTJA continues to explore the area to discover more hydrocarbons.

Most of Malaysia's natural gas production is offshore Sarawak and supports LNG exports from Bintulu. Petronas and other oil companies have made several discoveries of natural gas reserves since 2010 and commenced production from several fields, offsetting some of the declining production from mature gas basins in Peninsular Malaysia and in the shallow water blocks in Sarawak. Historically, Shell and Petronas have been the key developers of upstream assets supplying the MLNG liquefaction terminals. Shell and Petronas signed three more oil and gas PSCs with Petronas in 2012 and stepped up drilling efforts to continue developing natural gas and condensate production offshore Sarawak. The PSCs cover blocks SK319, SK318, and 2B in the Central Luconia Basin.

Two natural gas fields in Sarawak (NC3 in block SK316 and Kanowit field in block SK306) began production to serve as feedstock gas for the new liquefaction terminals commissioned in 2017. Block SK316 holds three key fields that will supply the newly commissioned ninth train of the existing MLNG terminal. Petronas began producing natural gas from the first field (NC3) at the end of 2016 and expects to bring the other two fields (NC8 and Kasawari) online by 2020. However, Petronas is considering selling up to 49 per cent of the Kasawari gas project, which contains an estimated 3.2 tcf in deepwater natural gas resources. The Kasawari field has elevated levels of carbon dioxide, so development requires advanced technologies. Petronas is seeking a skilled partner who can efficiently develop the Kasawari field in a more competitive gas price environment. Output from the Kanowit field began at the end of 2016 and is the initial feedstock for Malaysia's first floating liquefaction terminal. The Kanowit field is part of the larger Kumang Cluster, which began producing natural gas in 2011.

Newfield Exploration, which recently divested its Asian upstream assets, made a significant gas discovery in the SK-310 PSC offshore Sarawak in 2013. The company claimed the find could boost gas resources by 1.5 tcf. In 2014, SapuraKencana Petroleum, a Malaysia oil services company, purchased Newfield's Malaysian upstream assets and now holds 30 per cent of the SK-310 Block, while Petronas and Mitsubishi have 40 per cent and 30 per cent shares, respectively. SapuraKencana reported that it plans to bring the PSC's first field, B15, onstream towards the end of 2017 and the B14 field around 2020. In addition, SapuraKencana announced a significant gas reserve discovery in the PSC for block SK408 in 2016, signaling more near-term natural gas development potential in Sarawak.

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[165] BP (2019). BP Statistical Review of World Energy 2019 (68th Edition).

[166] MGA (2017). Malaysia: Natural Gas Industry Annual Review 2017 Edition. [online] Malaysia: Malaysian Gas Association (MGA). Available at: https://malaysiangas.com/wp-content/uploads/2019/03/Natural_Gas_Industry_Review-2017.pdf

The state of Sabah also holds reserves that are already under production or are scheduled to come online by 2020. A consortium consisting of Petronas (40 per cent), ConocoPhillips (30 per cent), and Shell, the operator, (30 per cent), are developing three contiguous natural gas and condensate fields, including Kebabangan, Kamunsu East, and Kamunsu East Upthrown Canyon (KBB Cluster) in northwestern Sabah. The KBB cluster is estimated to hold 4.7 tcf of gas. KBB production began in late 2014, and the KBB floating platform has a design capacity of 300 Bcf/y for natural gas, 80,000 b/d for crude oil, and 22,000 b/d for condensate. The platform acts as a hub for the development of these deepwater gas fields and ties in the Malikai crude oil field that came online at the end of 2016.

Other upstream developments offshore Sabah include the Kinabalu Non-Associated Gas project and the Rotan field in Block H. The Kinabalu project contains two natural gas fields and is scheduled to come online in mid-2017. Rotan and adjacent fields, operated by Murphy Oil in partnership with Pertamina of Indonesia and Petronas, have an estimated 1 tcf of reserves. These fields are located far offshore from existing infrastructure on the coast of Sabah and are slated to supply Malaysia's second floating liquefaction terminal by 2020.

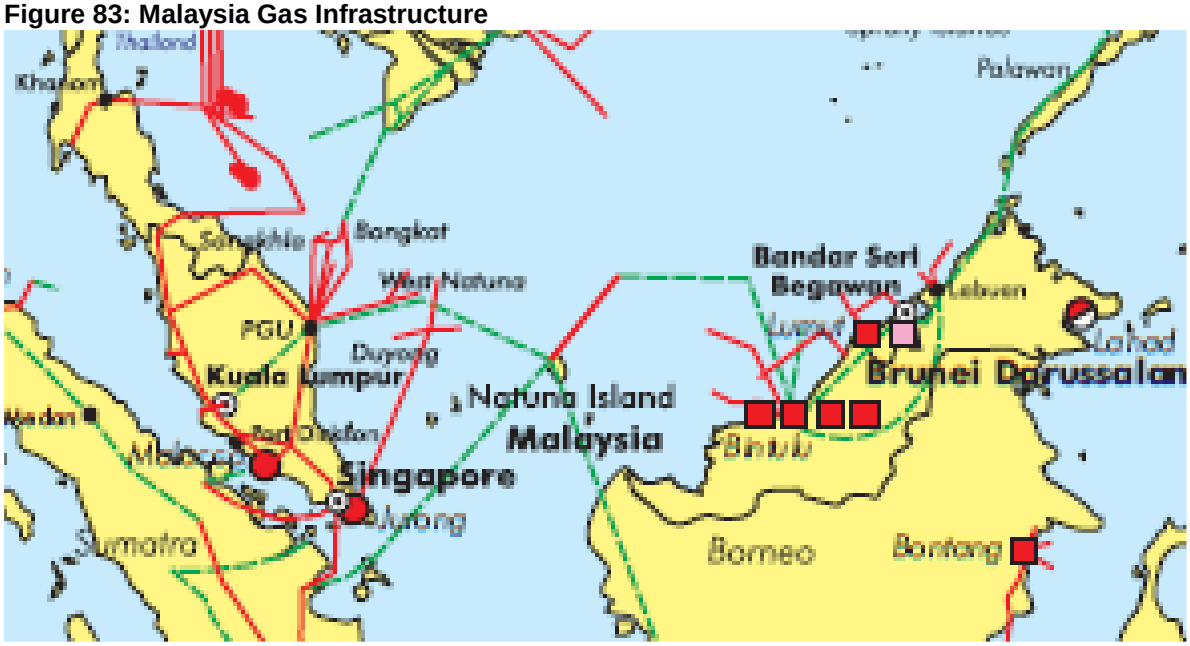
## Infrastructure and Contracts

### Pipelines

Malaysia has one of the most extensive natural gas pipeline networks in Asia, totaling about 1,530 miles. The Peninsular Gas Utilization (PGU) project, completed in 1998, expanded the natural gas transmission infrastructure on Peninsular Malaysia to 1,550 miles and has the capacity to transport 730 Bcf/y of natural gas. Other gas pipelines run from offshore gas fields to gas processing facilities at Kertih. A number of pipelines link Sarawak's offshore gas fields to the Bintulu LNG facility. However, limited gas distribution coverage exists in much of the Sarawak and Sabah states.

The Sabah-Sarawak Integrated Oil and Gas Project, installed in 2014, includes the 318-mile onshore Sabah-Sarawak Gas Pipeline (SSGP) and can transport about 365 Bcf/y of gas from Sabah's offshore fields to the Petronas LNG complex in Bintulu for liquefaction and export. Some natural gas from the terminal is also reserved for fueling downstream industrial projects and for power generation in Sabah. Other pipelines link natural gas fields located offshore Sabah to the Labuan Gas Terminal.

**Figure 83: Malaysia Gas Infrastructure**




Source: IEA Natural Gas Information

## Liquefaction Facilities

The Malaysia LNG (MLNG) complex located at Bintulu in the state of Sarawak is the main hub for Malaysia's natural gas industry and is operated by Petronas. Petronas owns majority interests in the facility's three LNG processing plants (Satu, Dua and Tiga), which are supplied by the country's offshore natural gas fields. MLNG is one of the largest LNG complexes in the world, with nine production trains and a total liquefaction capacity of 30 mtpa. Petronas began operating the facility's ninth train in January 2017. Japanese financing has been critical to the development of Malaysia's LNG facilities. The complex at Bintulu also hosts Shell's gas-to-liquid (GTL) project, which currently has a capacity of 15,000 b/d of petroleum liquids.

Petronas proposed two floating liquefaction terminals offshore Sarawak and Sabah to capture greater economic value from the country's smaller, more remote gas fields. These plants would have the flexibility to serve the export or domestic markets and are transportable to other locations. Both terminals will add another 131 Bcf/y of liquefaction capacity. The Petronas floating LNG (FLNG) Satu project, located off Sarawak near the Petronas LNG complex, has a capacity of 1.2 mtpa and is contracted to use natural gas from the Kanowit field for at least five years. Petronas FLNG Satu, which is the world's first floating liquefaction terminal, commenced commercial operations in early 2017.

PFLNG-2, the country's second proposed offshore LNG terminal, intends to monetize natural gas production from the Rotan field and other fields in Block H, northeast of Sabah in the South China Sea. The terminal has a design capacity of 1.2 mtpa, but it is uncertain whether the facility will serve domestic demand in Peninsular Malaysia or provide exports to other Asian markets. Petronas made a final investment decision on the project in early 2014. However, the low-price environment and Petronas' subsequent announced reduction of capital expenditures in the near term has caused the NOC to delay commencement of Petronas FLNG-2 by two years to 2020.

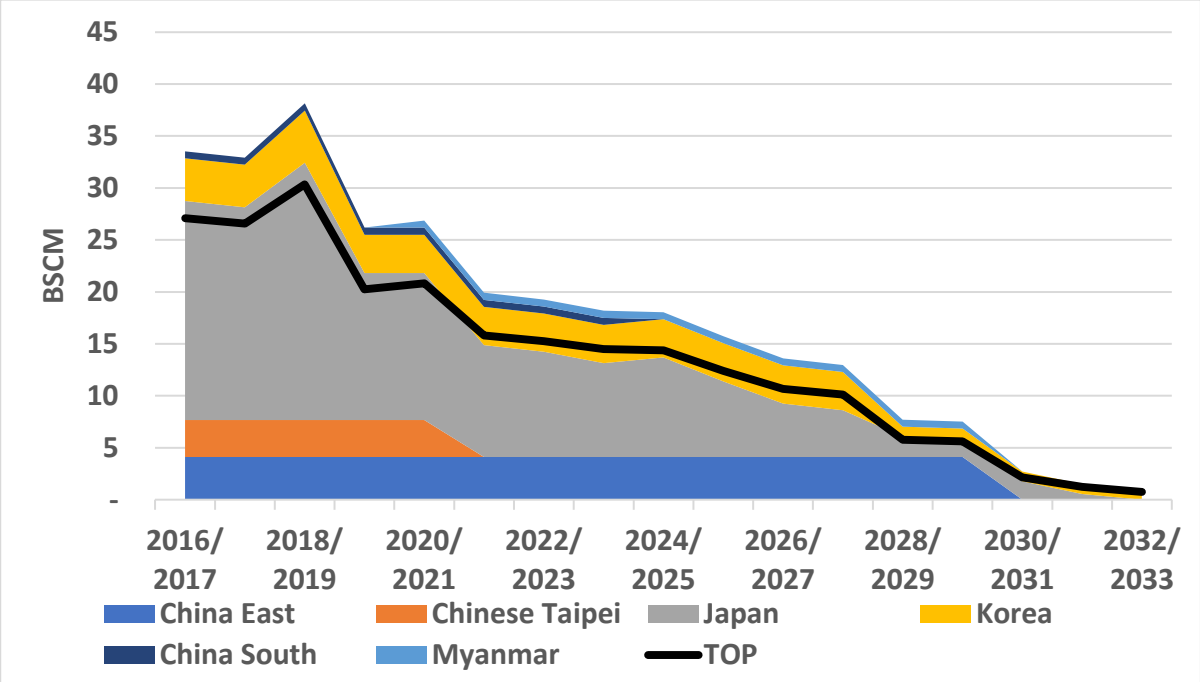
## Regasification Facilities

Malaysia's first regasification terminal, Lekas LNG, is located near Malacca, has a capacity of 3.8 mtpa and began operating in 2013. The second plant Pengerang LNG near Johor came online in 2018 with a capacity of 3.5 mtpa and is providing natural gas feedstock to the refining and petrochemical complex and to a power plant at the site. Several other regasification projects have also been proposed in the past few years, but some were cancelled.

## Export Contracts

Malaysia has a pipeline export contract with Singapore for 1.2 bcm/year which ends in 2023. There are multiple LNG contracts with Japanese importers as well as with Korea, Chinese Taipei and China buyers, and, more recently, Myanmar. Figure 84 shows the ACQs of these contracts over time and when they expire. The total ACQ is declining significantly in the early 2020s. Some contracts may be renewed with different volumes, pricing and durations, but the sellers, Petronas especially, may choose to trade more on a spot basis.

**Figure 84: Malaysia LNG Export Contracts ACQ**




Source: Nexant World Gas Model

### Import Contracts

Malaysia has a pipeline contract with Indonesia which began in 2003 and ends in 2022. Volumes have been as high as 9 bcm/year but are currently running at 6 bcm/year. There are long term LNG import contracts currently in operation from Australia (Gladstone) for 3.5 mtpa ending in 2034, Qatar (Qatargas) for 1.5 mtpa ending in 2032 and Norway (Equinor) for 0.1 mtpa ending in 2031. In the case of the Equinor contract it is not clear that the LNG has to be delivered to Malaysia. There were also short-term contracts with GDF Suez and Woodside for small volumes, when the first regas terminal started up, which have now expired.

## Government Policy and Regulation

Malaysia's state-owned Petronas dominates the natural gas sector. The company has a monopoly on all upstream natural gas developments, and it also plays a leading role in downstream activities and the liquefied natural gas trade. Most natural gas production comes from PSAs operated by foreign companies in conjunction with Petronas. Shell remains the largest gas producer and a key player in the development of deepwater fields in Malaysia. Other international companies that have sizeable upstream investments in Malaysia's natural gas fields include Murphy Oil, ConocoPhillips, Nippon Oil, INPEX, and Mitsubishi.

Gas Malaysia is the largest non-power natural gas distribution company in Malaysia and the only one that can operate on Peninsular Malaysia. Sarawak Gas Distribution Company, which is 70 per cent-owned by the government, serves Sarawak gas consumers, and Sabah Energy Corporation distributes natural gas in the Sabah state.

*Petroleum Development Act 1974*

Before 1974, the oil and gas industry in Malaysia was governed by the Petroleum Mining Act 1966 (Act 95) and it adopted the concession system to explore and produce petroleum resources in return for royalties and taxes. Shell and Esso dominated upstream production, downstream refining and sales. Many other foreign companies such as Conoco, Mobil, Aquitaine, Oceanic and Teiseki were also given exploration licenses by state governments through concession agreements.

The development of the oil industry as a significant activity in the country led to the enactment of the Petroleum Development Act in July 1974 and formation of the Petroleum Nasional Berhad (PETRONAS) in October 1974. This Act regulated the oil, gas and petrochemical industries and vested in PETRONAS the formulation of policies for effective control and development of onshore or offshore petroleum and related industries[167].

"Petroleum Development Act 1974 is an Act to provide for exploration and exploitation of petroleum whether onshore or offshore by a Corporation in which will be vested the entire ownership in and the exclusive rights, powers, liberties and privileges in respect of the said petroleum, and to control the carrying on of downstream activities and development relating to petroleum and its products; to provide for the establishment of a Corporation under the Companies Act 1965 [Act 125] or under the law relating to the incorporation of companies and for the powers of that Corporation; and to provide for matters connected therewith or incidental thereto."

Under this Act, ownership of and the exclusive rights, powers, liberties and privileges in respect of the said petroleum, and control of downstream activities and development relating to oil and its products were vested in PETRONAS. PETRONAS is entitled to carry out the business of processing, refining of petroleum or manufacturing of petrochemical products from oil unless permission is given to any other entity by the Government. All upstream activities such as exploration, development and production of resources, are carried out through production sharing contracts (PSCs) under the Petroleum Development Act 1974. In 1976, PETRONAS and the major companies operating in Malaysia signed Production Sharing Agreements (PSAs) which determined the distribution of oil production between these parties to explore for and develop resources. To further develop the natural gas industry in Malaysia, PETRONAS carried out the Gas Masterplan Study in 1981, which created a long-term strategy and integrated planning for gas industry development in Malaysia as well as recommending the development of Peninsular Gas Utilisation (PGU) pipeline network[168].

*Petroleum Regulation Act 1974*

The establishment of the Petroleum Regulations (1974 further amended in 1975, 1981, and 1991) set out the regulation and licensing of upstream, and downstream activities to different entities. Under this Act, PETRONAS is responsible for the planning, investment and regulation of all upstream activities. Meanwhile, the Ministry of International Trade and Industry (MITI) and the Ministry of Domestic Trade, Co-Operatives and Consumerism (MDTCC) regulate all downstream activities.

PETRONAS regulates and issues licences for upstream activities, which include:

- to commence or continue any business or service, onshore or offshore relating to the exploration, exploitation, winning and obtaining of petroleum and, in particular involving the supply and use of rigs, derricks, ocean tankers and barges;
- to commence or continue any business or service involving the supply of equipment and facilities and services required in connection with the exploration, exploitation, winning and obtaining of petroleum.

For downstream activities, MITI regulated licensing to commence or continue any business of processing or refining of petroleum or manufacture of petrochemical products from petroleum. MDTCC performed the same function in relation to marketing and distribution of petroleum or petrochemical products.

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[167] MEA (1981). Fourth Malaysia Plan 1981-1985. [online] Malaysia: Ministry of Economic Affairs (MEA). Available at: https://www.mea.gov.my/en/rmk/fourth-malaysia-plan-1981-1985 SITE DID NOT RESPOND

[168] MEA (1981). Fourth Malaysia Plan 1981-1985. [online] Malaysia: Ministry of Economic Affairs (MEA). Available at: https://www.mea.gov.my/en/rmk/fourth-malaysia-plan-1981-1985
MGA (2017). Malaysia: Natural Gas Industry Annual Review 2017 Edition. [online] Malaysia: Malaysian Gas Association (MGA). Available at: https://malaysiangas.com/wp-content/uploads/2019/03/Natural_Gas_Industry_Review-2017.pdf

*Gas Supply Act 1993*

However, the regulatory system changed following the Gas Supply Act implementation in 1993 and establishment of Energy Commission (EC) in 2001 as the downstream regulator replacing MITI and MDTCC. The Gas Supply Act 1993 (gazetted on 4 February 1993) safeguards the interests of industrial, commercial and residential consumers who receive gas supply through pipelines.

"The Gas Supply Act 1993 is to provide the licencing of the supply of gas to consumers through pipelines and related matters, the supply of gas at reasonable prices, the control of gas supply pipelines, installations and appliances with respect to matters relating to safety of persons and for purposes connected therewith."

With the implementation of this Act, the relevant sections in the Petroleum Development Act 1974 of the supply of gas through pipelines were amended (to avoid duplication of section 6(3A) of the Petroleum Development Act 1974) and all regulation related to supply of gas through pipelines came under the Gas Supply Regulations 1997 (which entered into force on 17 July 1997). These regulations outlined procedures for the issuance of licences for gas pipelines, gas installations, gas fitting and appliances used in pipelines or installations. The two categories of licences under these regulations were gas utility licences and private gas licences. The Department of Gas Supply was formed in 1993 under the Prime Minister's Department to regulate gas distribution. In 2001, this department was dissolved and the Gas Supply Act 1993 further amended to authorise the Energy Commission to regulate activities related to the supply of gas through pipelines.

*Liberalisation of the Gas Market – the Gas Supply (Amendment) Act 2016*

The Gas Supply Act 1993 [Act 501], which is referred to as the "principal Act" in this Gas Supply (Amendment) Act, was amended by substituting the following:

"An Act to provide for the licensing of the import into regasification terminal, regasification, shipping, transportation, distribution, retail or use of gas in the supply of gas through pipelines and related matters, the supply of gas at reasonable prices, the control of gas supply pipelines, installations and appliances with respect to matters relating to safety of persons in the distribution, retail or use of gas and for purposes connected therewith."

This Act (gazetted on 9 September 2016) came into force on 16 January 2017, and further expanded the regulatory role of Energy Commission and implementation of third-party access (TPA) in Peninsular Malaysia. The amended Act only applies to Peninsular Malaysia and Sabah and excludes the state of Sarawak:

"…The operation of the principal Act is deemed to be suspended for the state of Sarawak from 17 July 1997, and for that purpose it shall be treated as if an order has been made under subsection 1(2) of the principal Act…" (Clause 4A. (2))

## Supply and Demand Projections

As already noted, gas demand in Malaysia is predominantly in the power sector and industry so these two sectors will drive gas demand.

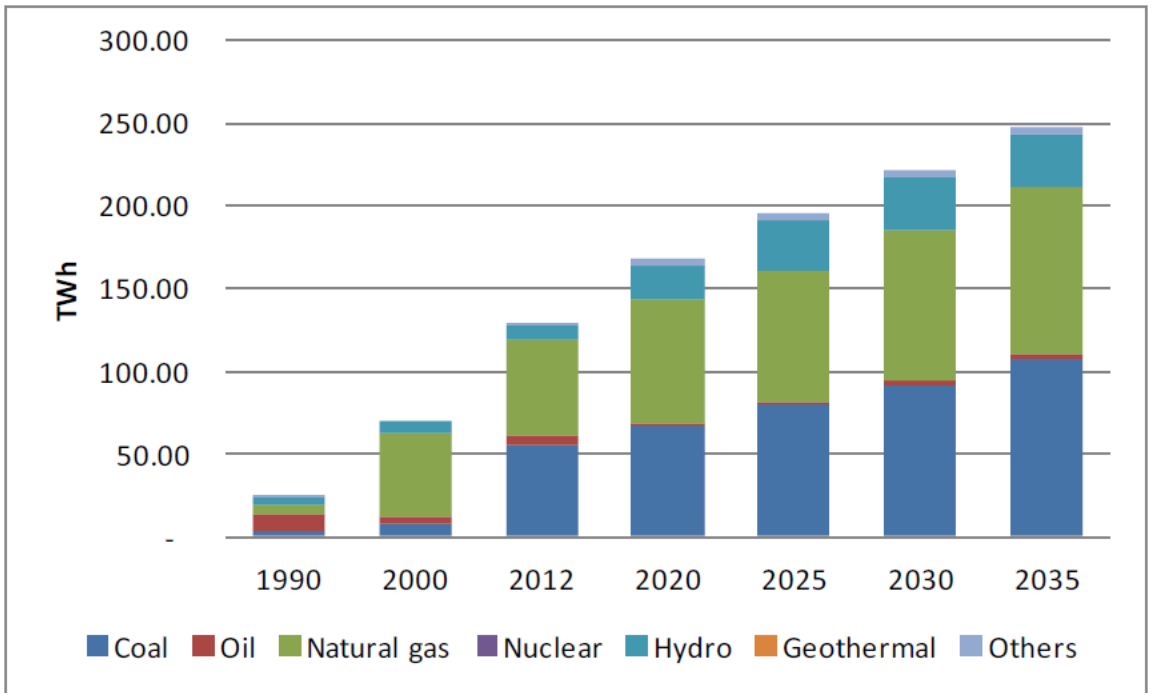
### External Demand Projections

#### *East Asia Report*[169]

A 2015 report looked at the energy outlook for the East Asia region. This suggested that total system demand would increase to some 220 TWh by 2030 and almost 250 TWh by 2035 in a Business as Usual scenario.

[169] Zulfiki.Z. (2015), 'Malaysia Country Report' in Kimura, S. and H. Phoumin (eds.) in Energy Outlook and Energy Saving Potential in East Asia 2016. ERIA Research Project Report 2014-33, Jakarta: ERIA, pp.160-177.

**Figure 85: Malaysia Electricity Generation BAU Scenario**




Source: East Asia Report

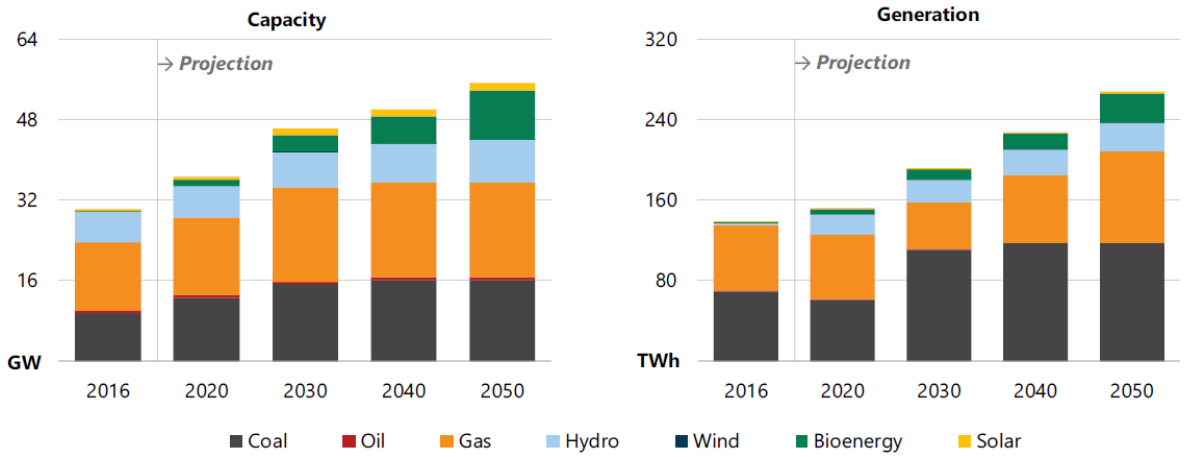
Gas was expected to lose some market share to coal and others by 2030 and 2035, but gas demand in power would increase by 10 per cent in 2030 and 20 per cent in 2035 compared to 2017. Overall gas share in primary energy consumption would be expected to increase slightly, but with the continuing rise in total energy consumption, gas demand could double by 2035 compared to 2017.

### *APEC Energy Demand and Supply Outlook – 7th Edition*[170]

A more recent outlook is the regular APEC energy outlook, the 7th edition of which was published in May 2019. This included a Business As Usual (BAU) scenario but also a 2 Degrees C (2DC) scenario. The BAU scenario suggested annual system demand rising to 180 TWh by 2030, 220 TWh by 2040 and 260 TWh by 2050, with gas broadly maintaining its usage in generation in 2020, declining in 2030 as coal picks up, before rising again in 2040 and further in 2050.

[170] https://aperc.ieej.or.jp/publications/reports/outlook.php

**Figure 86: APEC Outlook - Power Generation Capacity and Generation in BAU 2016 to 2050**

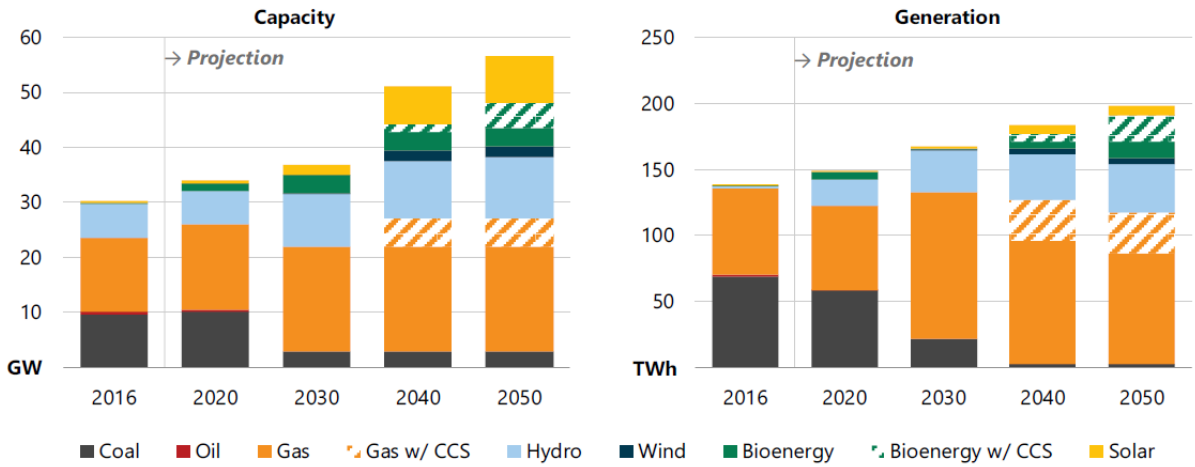



Source: APEC Energy Demand and Supply Outlook

This suggests 13 bcm of gas demand in power in 2030, 18 bcm in 2040 and 24 bcm in 2050, compared to 17 bcm in 2017.

The 2DC scenario has a very different outlook, as coal disappears from the mix and gas – partly with CCS – gaining share. This would suggest gas demand of 28 bcm in 2030 compared to 17 bcm in 2017. Gas demand would be 30 bcm in 2040 and 26 bcm in 2050 in the 2DC scenario.

**Figure 87: APEC Outlook - Power Generation Capacity and Generation in 2DC 2016 to 2050**




Source: APEC Energy Demand and Supply Outlook

Industrial energy demand in total in the BAU scenario grows gradually to 2050 but the growth comes in gas and electricity so total gas demand in industry rises from 7.2 bcm in 2017 to 8.5 bcm in 2050.

In the 2DC scenario, industrial energy demand growth is lower than in the BAU scenario and there is some substitution of gas with biomass so gas demand is little changed from the 2017 level.

### iii. Final Report on Natural Gas Demand Potential in Asia[171]

This report by ERIA and IEEJ from 2018 considered natural gas demand potential through to 2030 in the region. For Malaysia the report sees the potential to double gas demand by 2030 from 2017 levels, principally led by the power sector.

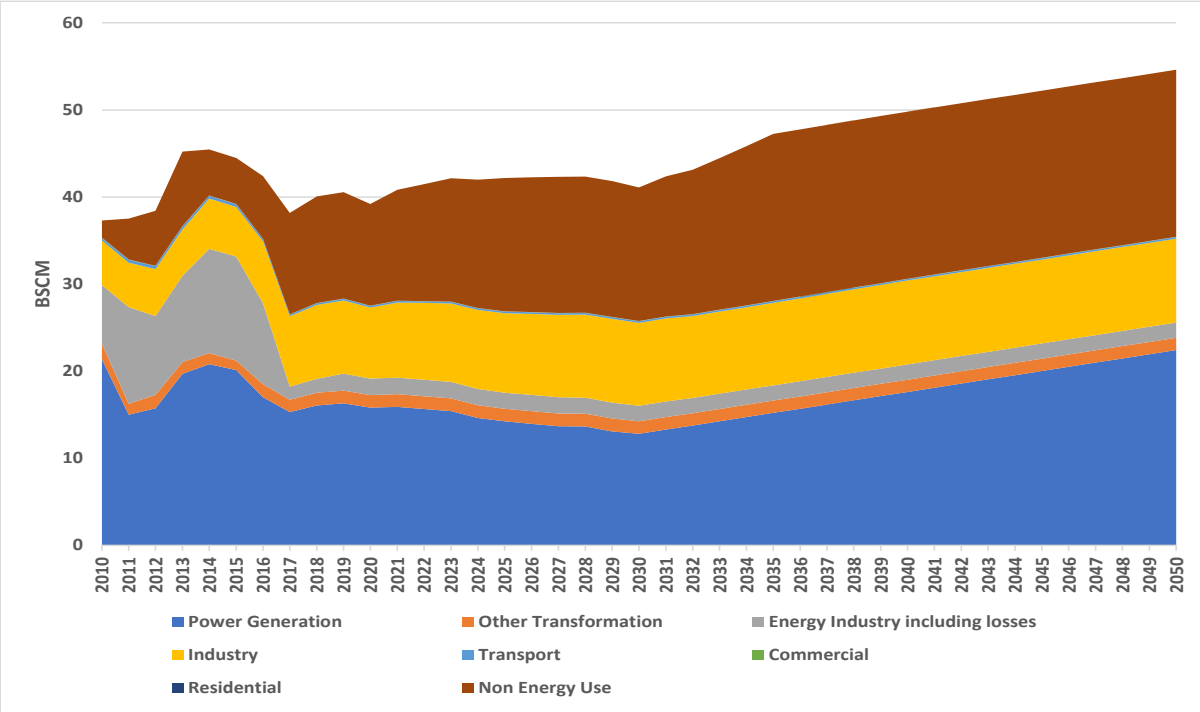
#### *Conclusions on Demand*

Both the East Asia report and the ERIA/IEEJ report are much more optimistic on gas demand, mainly in power, than the APEC report. This largely depends on whether, in the next 10 years, coal generating capacity grows strongly and displaces gas generation. After 2030 gas begins to regain market share in power as demand for electricity grows. As a base case the APEC report can be used in general with the other reports showing the upside potential if coal doesn't displace gas in power as much.

## Gas Supply and Demand Balance

The prospects for gas production in Malaysia are somewhat mixed. Production from the Malaysian-Thailand Joint Development Area is expected to decline as is production from other fields offshore Peninsular Malaysia. Production to feed the LNG plants at Bintulu and the FLNGs is projected to be at best maintained, since new developments look to be high in $CO_2$ and/or $H_2S$ and expensive to develop. This should enable LNG exports to be maintained from Borneo, but with growing demand and falling supply in Peninsula Malaysia, LNG imports will rise.

**Figure 88: Malaysia Base Case Demand by Sector 2017 to 2050**

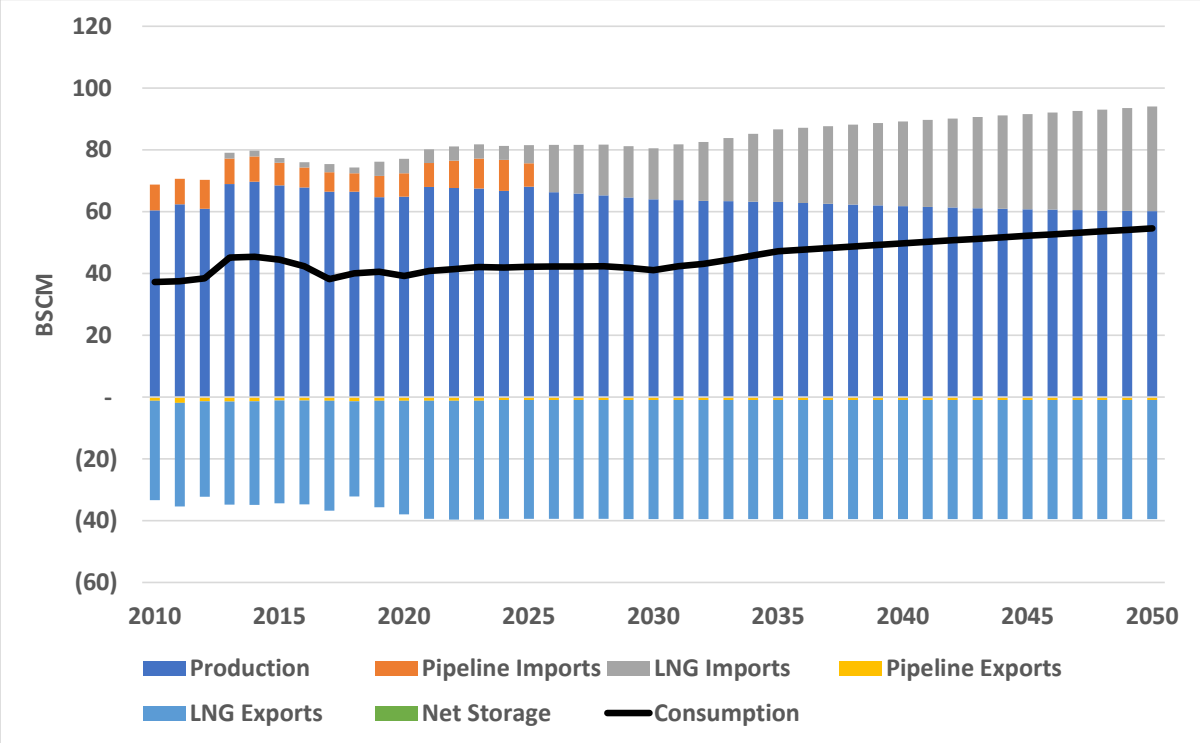



Source: IEA, OIES, Nexant World Gas Model

On the demand side, there is little growth through to 2030 as coal generation increases, but thereafter gas-fired power usage increases, in line with electricity generation. There is also expected to be growth in the use of gas as a feedstock for fertilizer production. LNG imports pick up from the mid-2020s as pipe imports from Indonesia cease, and demand growth picks up.

[171] The 7th ASEAN+3 Oil Market and Natural Gas Forum and Business Dialogue, ERIA and IEEJ, Bangkok, Thailand, March 2018

**Figure 89: Malaysia Base Case Supply Demand 2017 to 2050**




Source: IEA, OIES, Nexant World Gas Model

## Conclusions

Malaysia is expected to broadly maintain the level of LNG exports throughout the projection period. With gently increasing consumption and slowly falling production, especially in those fields delivering directly to the peninsular region, the increasing supply gap is expected to be filled by LNG imports. This is especially so after pipe imports from Indonesia cease. Small volumes of gas may continue to be exported to Singapore via pipe, even after the supply contract ends, but these will effectively be LNG imports diverted to Singapore.

Key uncertainties surround the demand side and whether the anticipated growth of natural gas as a feedstock is realized in the 2020s, plus growth in the use of gas in power in the 2030s, as coal-fired generation stops growing. Gas, therefore, benefits from the growth in electricity generation capacity and electricity demand. As with other countries in the region, gas might be expected to benefit from a more rapid decarbonization scenario as coal-fired generation is shut down.

## MYANMAR

### Historic Supply and Demand

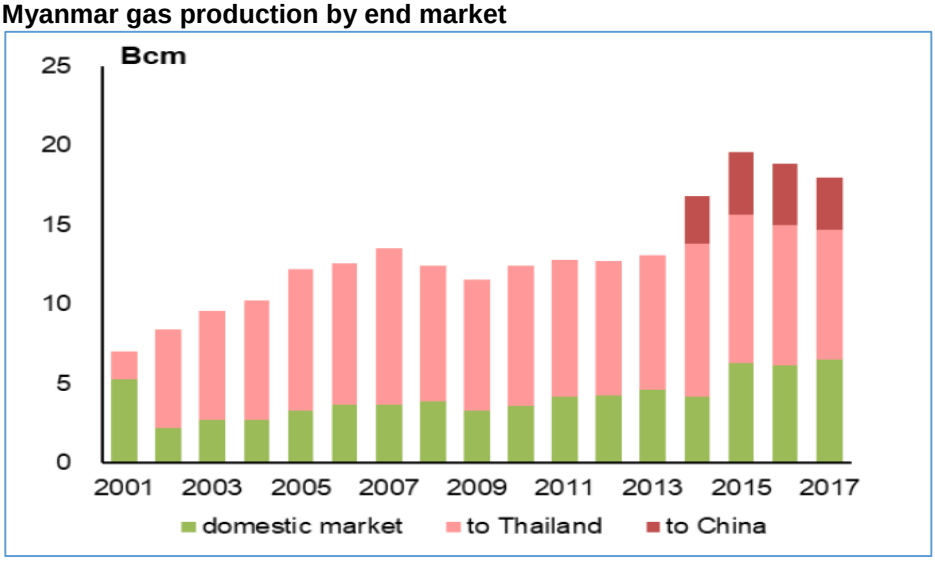
Myanmar oil and gas production has a long history, starting with production from the onshore Yenangyaung field during the 19th century. Significant gas production only started following development of the offshore Yadana and Yetagun fields in the 1990s. A summary of the main offshore producing fields is given in Table 7 and Figure 90.[172] There are also several onshore gas fields, but their production in total was only 50 mmscf/d in 2018.[173]

**Table 7: Main Myanmar gas fields in production**

| Gas Field | Initial Reserves (tcf) | Production Capacity (mmscf/d) | Export capacity (mmscf/d) | Export destination | Start of Operation |
|---|---|---|---|---|---|
| Yadana | 6.4 | 850 | 560 | Thailand | 1998 |
| Yetagun | 2.3 | 200 | 150 | Thailand | 2000 |
| Shwe | 3.3 | 550 | 340 | China | 2013 |
| Zawtika | 1.7 | 300 | 200 | Thailand | 2014 |

Source: Asian Development Bank (2016), MOEE (2017)

**Figure 90: Myanmar gas production by end market**

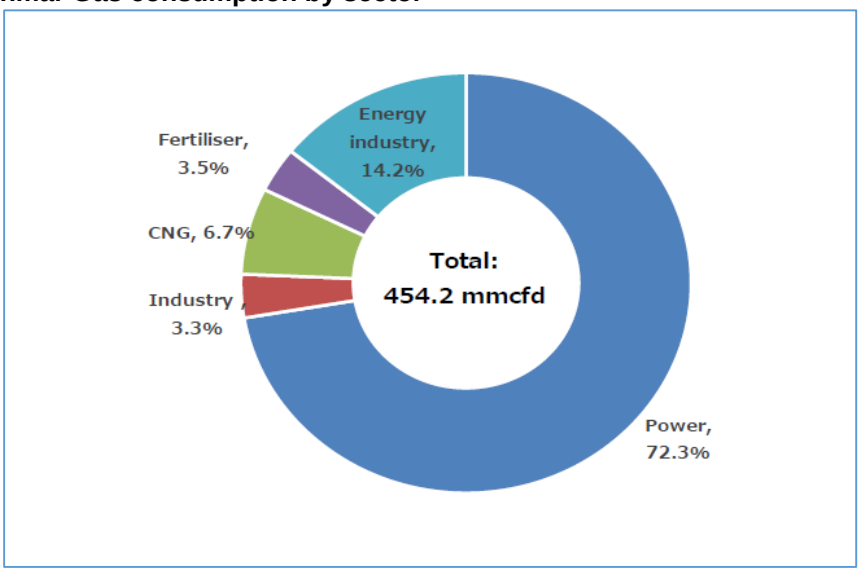



Source: Myanmar Natural Gas Master Plan 2017

Figure 90 shows that only around 1/3 of total gas production is used domestically, with the rest being exported to either China or Thailand. Over 70 per cent of domestic gas consumption is used in power generation, as shown in Figure 91,

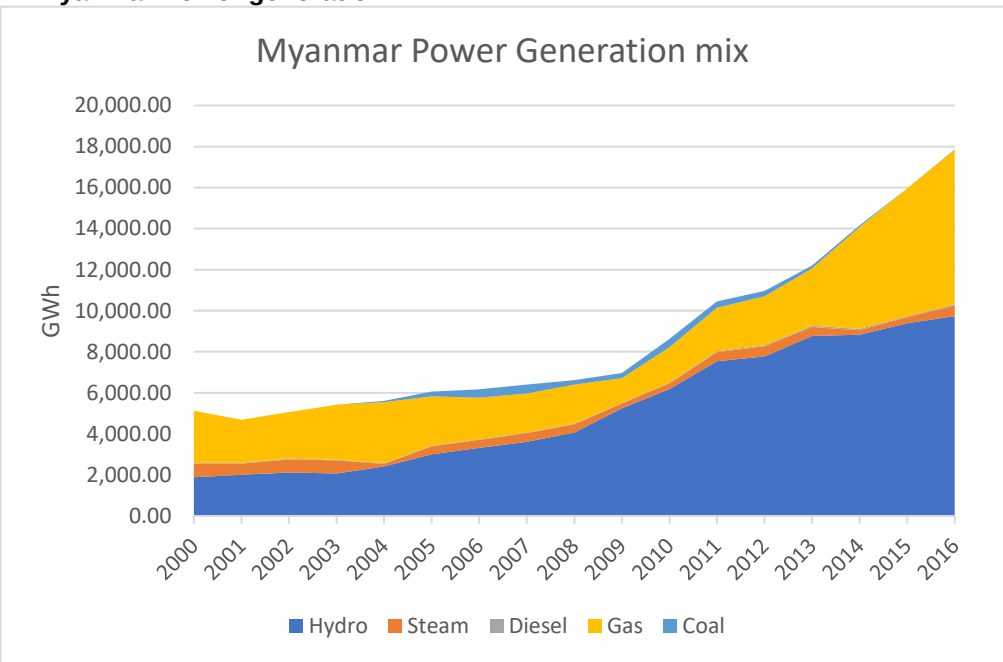
[172] Myanmar Natural Gas Masterplan (2017): https://www.eria.org/publications/natural-gas-master-plan-for-myanmar/
[173] https://oxfordbusinessgroup.com/overview/reserve-exploration-projects-pipeline-and-moves-improve-supply-chain-aim-make-use-untapped-potential

**Figure 91: Myanmar Gas consumption by sector**




Source: Myanmar Natural Gas Master Plan 2017

**Figure 92: Myanmar Power generation mix**




Source: OIES, data from Myanmar Energy Statistics

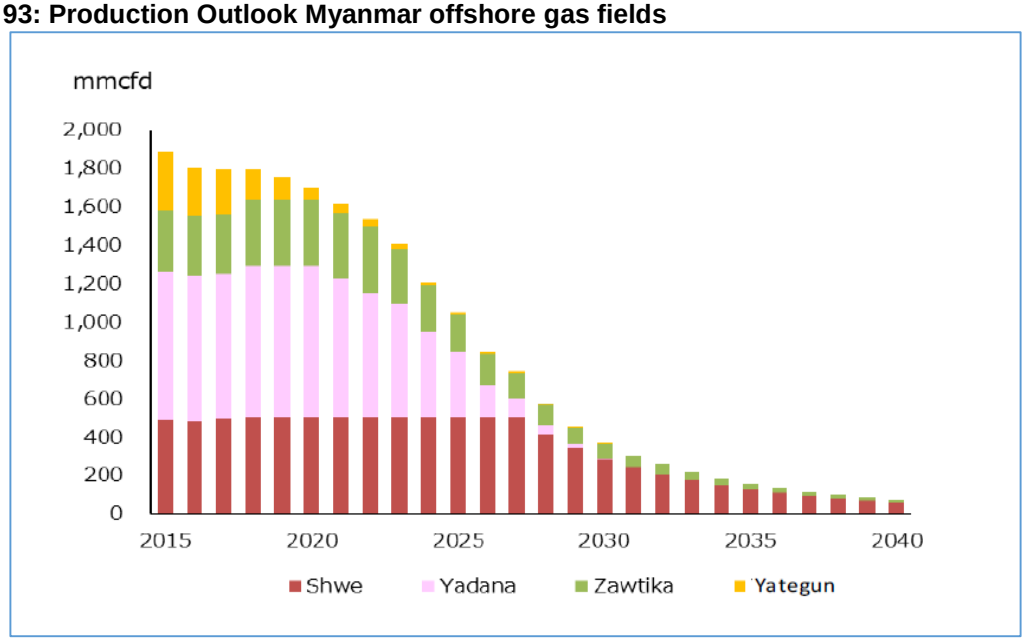
The power generation mix has been dominated by hydro and gas[174], as shown in Figure 92 92. Total power generation capacity in 2019 was 5,642MW, of which 3,255MW was hydro, 2,175MW gas, 120MW coal and 92MW diesel.[175] Overall electrification in the country is low, with the Ministry of Electricity and Energy announcing in December 2019 that 50 per cent of the population was covered

[174] Myanmar Energy Statistics (2019): https://www.eria.org/publications/myanmar-energy-statistics-2019/
[175] https://greatermekong.org/sites/default/files/Attachment per cent2011.3_Myanmar.pdf page 9

by the electricity network, up from 43 per cent in 2018. The capital, Yangon, accounted for 42 per cent of total electricity consumption in 2018, down from 50 per cent in 2013.[176]

Production from all of the existing fields is expected to decline significantly over the next 10 years as shown in Figure 93.

**Figure 93: Production Outlook Myanmar offshore gas fields**




Source: Myanmar Natural Gas Master Plan 2017

## Infrastructure

Myanmar has an extensive gas pipeline network as shown in Source: Myanmar Natural Gas Master Plan 2017

94

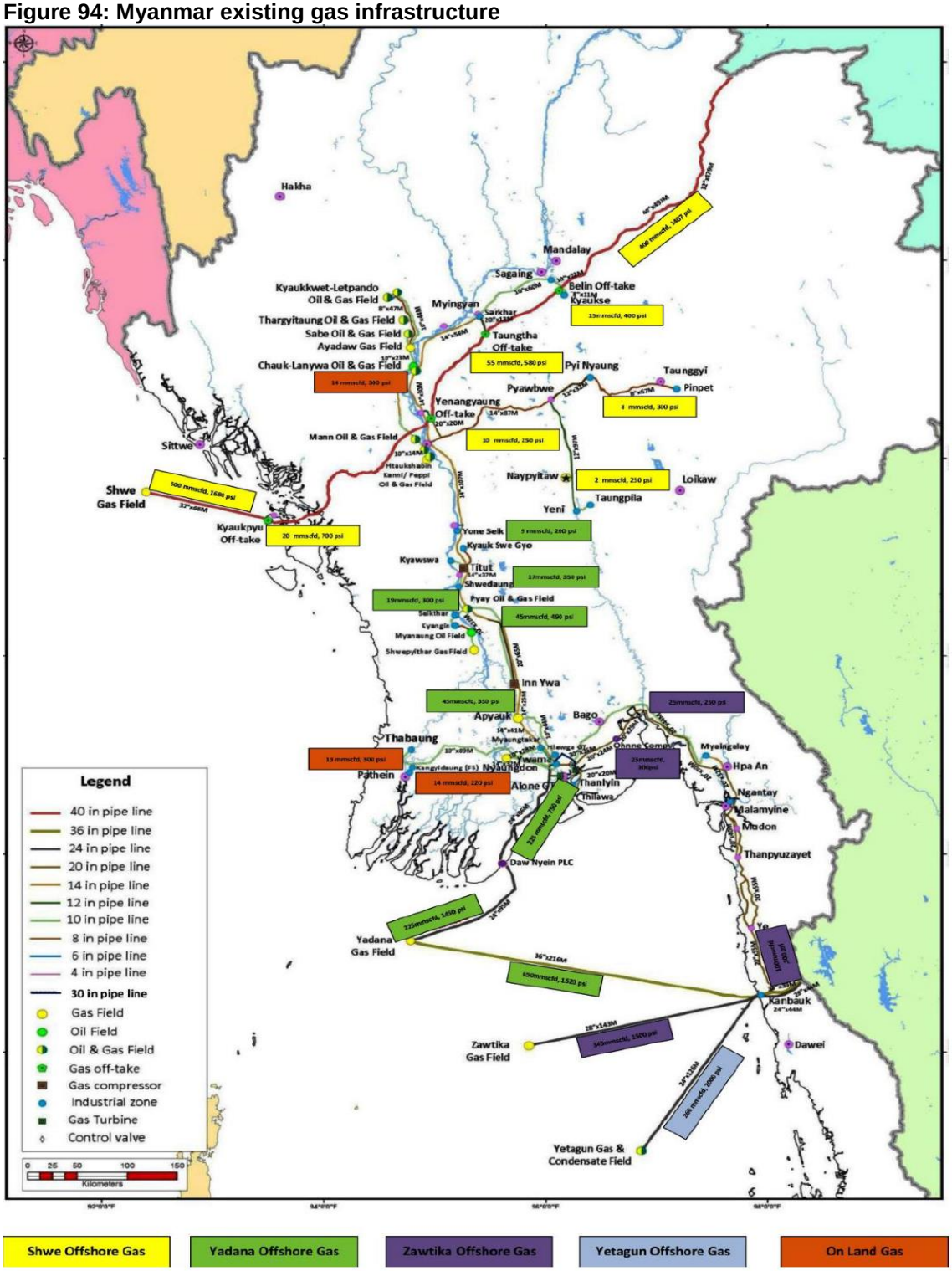
While the map shows a north-south connecting pipeline, it is not in use on account of corrosion, pending a repair.[177] Thus there are two separate pipeline systems:

- A northern system primarily linking the Shwe field to the export pipeline to China;
- A southern system linking the major southern offshore fields (Yadana, Zawtika and Yetagun) to the export system to Thailand as well as to the capital Yangon.

With an expectation of growing domestic gas demand and limited potential to increase domestic production or reduce exports, Myanmar has been considering LNG imports for some time.

[176] https://oxfordbusinessgroup.com/overview/reserve-exploration-projects-pipeline-and-moves-improve-supply-chain-aim-make-use-untapped-potential
[177] Myanmar Natural Gas Masterplan, p85.

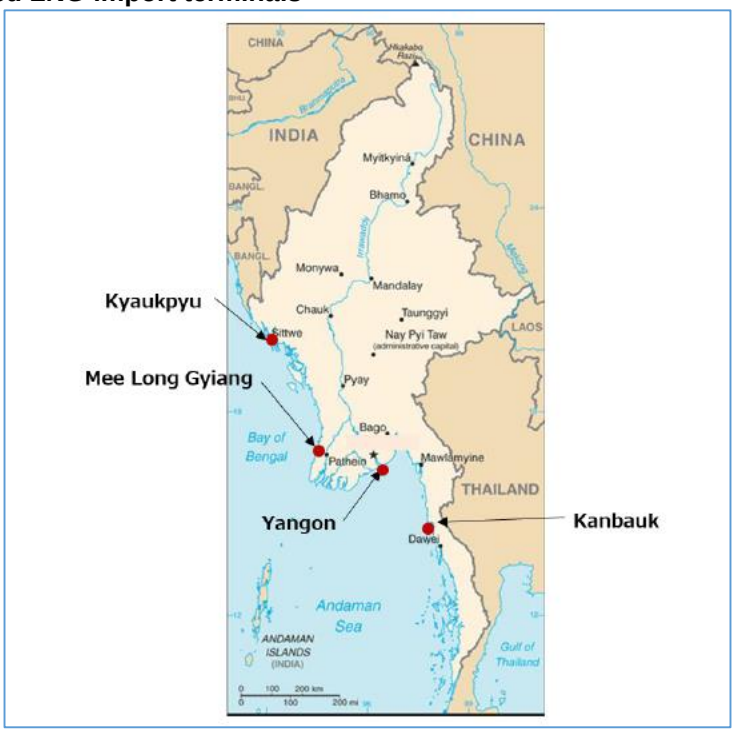
**Figure 94: Myanmar existing gas infrastructure**




Source: Myanmar Natural Gas Master Plan 2017

According to the 2017 Natural Gas Master Plan, four LNG import terminals were being considered, three on the southern network and one on the northern network, as shown in 5 and Table 8.

**Figure 95: Projected LNG import terminals**




Source: Myanmar Natural Gas Master Plan 2017

**Table 8: Proposed LNG import projects**

| Project | Import Capacity (mtpa) | Installed generation (MW) |
|---|---|---|
| Alone (Yangon area) | 0.4 | 356 |
| Mee Long Gyaing | 1.6 | 1,390 |
| Kanbauk | 1.0 | 1,230 |

Source: Myanmar Natural Gas Master Plan 2017

All of these projects in the 2017 masterplan only made slow progress and in mid-2019 were reported as being "delayed but not dead"[178]. A major hurdle appeared to be the inability to secure a bankable power purchase agreement for offtake of electricity from the power plants which were intended to underpin the investment in each terminal. In January 2020, it was reported, in connection with a visit of Chinese President Xi Jinping to Myanmar, that work on Mee Long Gyaing was expected to begin in mid-2020, but it is likely that progress will have been further delayed by Covid-19.

A sudden acceleration in LNG development followed a series of major power cuts in May 2019, which led to the Ministry of Electricity and Energy announcing a tender in June 2019 for five emergency power projects totalling 1,040 MW, of which 3 plants would use imported LNG.[179] In July 2019, a consortium of VPower and CNTIC was awarded the tender, with a very short deadline to start LNG imports by April 2020.

Two of the three power plants (Thaketa, 400MW and Thanlyin, 350MW) are in Yangon and are intended to be supplied by a newbuild pipeline from an FSRU receiving terminal located on the Yangon River south of the city. Because of the shallow draft in the river, it is intended to supply the 126,000m$^3$ FSRU with a 28,000 m$^3$ shuttle tanker. Larger LNG carriers will provide floating storage offshore while the

[178] https://frontiermyanmar.net/en/lng-projects-delayed-not-dead
[179] https://frontiermyanmar.net/en/race-against-time-will-emergency-power-projects-be-ready-for-hot-season

shuttle tanker transfers the cargo to the FSRU. Perhaps not surprisingly, particularly in view of Covid-19 restrictions, the April 2020 deadline was missed, but an initial cargo arrived aboard the 28,000 $m^3$ VPower Global in June 2020 to start gas-fired power generation at the Thaketa power plant. Longer term, the 126,000$m^3$ LNG carrier North West Sea Eagle is currently being converted to an FSRU, will be renamed CNTIC VPower Energy and will be moored at a new jetty, once completed.

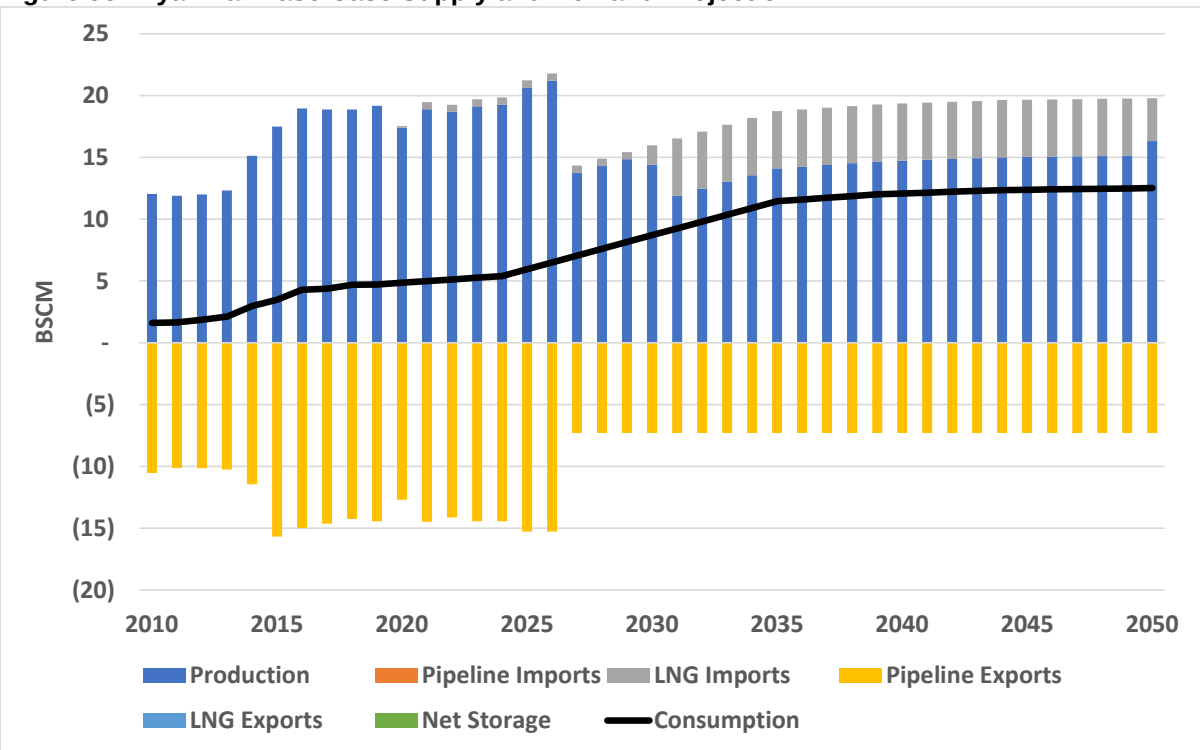
The third power plant (150MW) is at Kyaukpyu in the north of the country, and it is understood it will be supplied by an LNG terminal under construction nearby.[180] The LNG terminal is part of a larger port development and forms part of the Belt and Road Initiative cooperation with China.

## Supply and Demand Projections

The main source of gas demand is in the power generation sector, with the government plan to increase electrification from the current 50 per cent to 100 per cent of households by 2030. According to forecasts from the Ministry of Electricity and Energy[181] power generation capacity is expected to grow from the current 6GW to around 20GW by 2030. The share of domestic gas-fired generation is expected to fall from 26 per cent (2.2GW) today to 14 per cent (2.8GW) by 2030. On the other hand, LNG- fired generation is expected to grow to around 25 per cent of the capacity mix, or around 5GW. This would require completion of all the currently proposed LNG developments, totalling around 3GW, plus additional capacity of around 2GW from projects which have not yet been identified.

Now that Myanmar has started imports of LNG, albeit in a small way, it increases confidence that the subsequent LNG import plans will come to fruition. On that basis we project a base case LNG demand for 2030 of 3 mtpa with a potential upside to 5mtpa.

**Figure 96: Myanmar Base Case Supply and Demand Projection**




Source: IEA, OIES, Nexant World Gas Model

[180] https://www.globalnewlightofmyanmar.com/hong-kong-firm-to-sell-power-after-building-power-plants-in-kyaukpyu/
[181] https://greatermekong.org/sites/default/files/Attachment per cent2011.3_Myanmar.pdf

## VIETNAM

### Historic Supply Demand

There are a number of key themes that underpin the Vietnamese energy economy and have already had, and will continue to have, an important bearing on the role of gas in the country. The first, and most general, is that in common with many countries in SE Asia the economy has been growing rapidly and is forecast to continue to do so once the impact of the COVID 19 pandemic has receded. Over the past two decades GDP has almost tripled and GDP/capita has more than doubled, and over the next two decades projected economic growth estimates range from 5-7 per cent pa,[182] so significant expansion is expected to continue.

This growth, combined with a continuing rise in the population (from 80 million in 2000 to 95 million in 2016), has generated significant expansion of energy demand. Total primary energy demand has risen from 30 mtoe in 2000 to 80 mtoe in 2016, but the impact on the use of hydrocarbons has been even more dramatic because of another underlying trend, the switch away from traditional biomass (i.e. the burning of wood and other organic matter). Urbanisation of the population has been a major trend, which has in turn led to a rapid electrification of the economy and has caused power demand and therefore the demand for fuel inputs for the power sector to increase sharply.

Industrial demand growth has also been strong, focussed on the iron and steel, chemical and fertiliser sectors where energy use is intense. Vietnam has yet to see any major shift to becoming a service economy, although the authorities have been trying to encourage greater energy efficiency.

Vietnam's major sources of indigenous energy are hydro and coal. The former has been fully exploited and forms an important part of the electricity system, while the latter is used extensively across the entire economy. Indeed, in contrast with many Asian countries the use of coal is expected to increase, mainly because oil and gas resources are either much smaller or are in decline.

This focus on coal has drawn criticism from external agencies, not least the World Bank,[183] because it clearly will have a negative impact on Vietnam's contribution to climate change. The country made some relatively modest promises on carbon emission targets at the COP21 meeting in Paris and even these would appear to be under threat if the country's plans to expand the use of coal are implemented.

However, Vietnam has also become a net energy importer (as of 2015), which has encouraged a focus on developing energy resources for the domestic market. This includes rapid expansion of renewables (which will obviously help with climate targets) and expansion of the gas sector, where potential for higher production exists. A key question is which of these options takes priority, and the government has announced a number of energy and climate policy targets which would seem to favour renewables. Having said this, the Vietnamese authorities are also committed to starting LNG imports in the 2020s as they are keen to encourage growth in gas demand (again to offset some of the impact of coal use), with regasification terminals planned to be linked to specific onshore infrastructure – either new power stations or industrial plants.

Vietnam's energy consumption has been growing rapidly from the mid-1980s onwards, with the CAGR of total primary energy demand since 1990 being 9.7 per cent. This huge expansion is shown in Figure 97, and it is clear that despite population growth over that time period energy consumption per capita has also been on a rapid upward trajectory. This reflects the country's transformation from a relatively undeveloped economy to one of the Asian tigers over the past three decades, fuelled in particular by the provision of indigenous energy to the power sector which has allowed the electrification of much of the country to take place. In addition, the rapid development of heavy industry has also underpinned economic growth and has accelerated energy demand.

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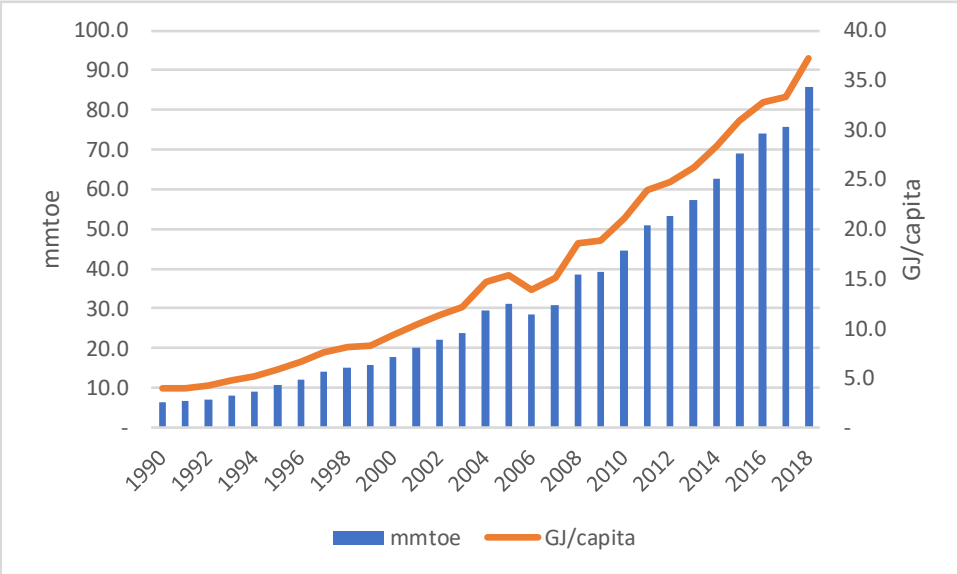
[182] EREA & DEA: Vietnam Energy Outlook Report 2019 (2019), p.14
[183] Vietnam: Maximising Finance of Development in the Energy Sector, 2018, World Bank Group

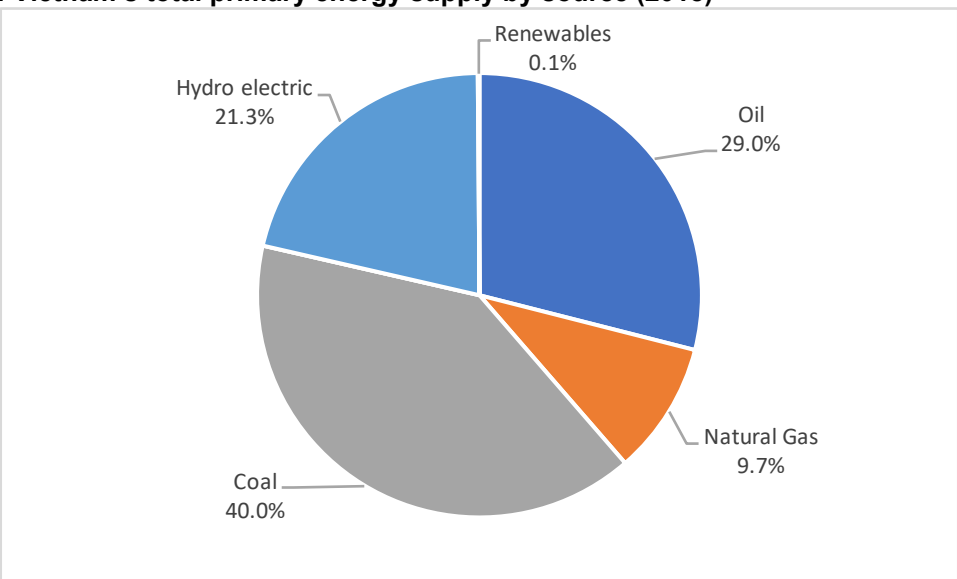
**Figure 97: Vietnam's primary energy demand (1990-2018)**




Source: BP Statistical Review of World Energy

The current breakdown of total primary energy is shown in Figure 98, where it is clear that the main sources are coal, oil and hydro, with gas in fourth place and some way behind with less than 10 per cent market share. This reflects the historic balance of Vietnam's indigenous energy supply, with large coal reserves, significant hydro resources in the north of the country and some large oil reserves discovered offshore.

**Figure 98: Vietnam's total primary energy supply by source (2018)**



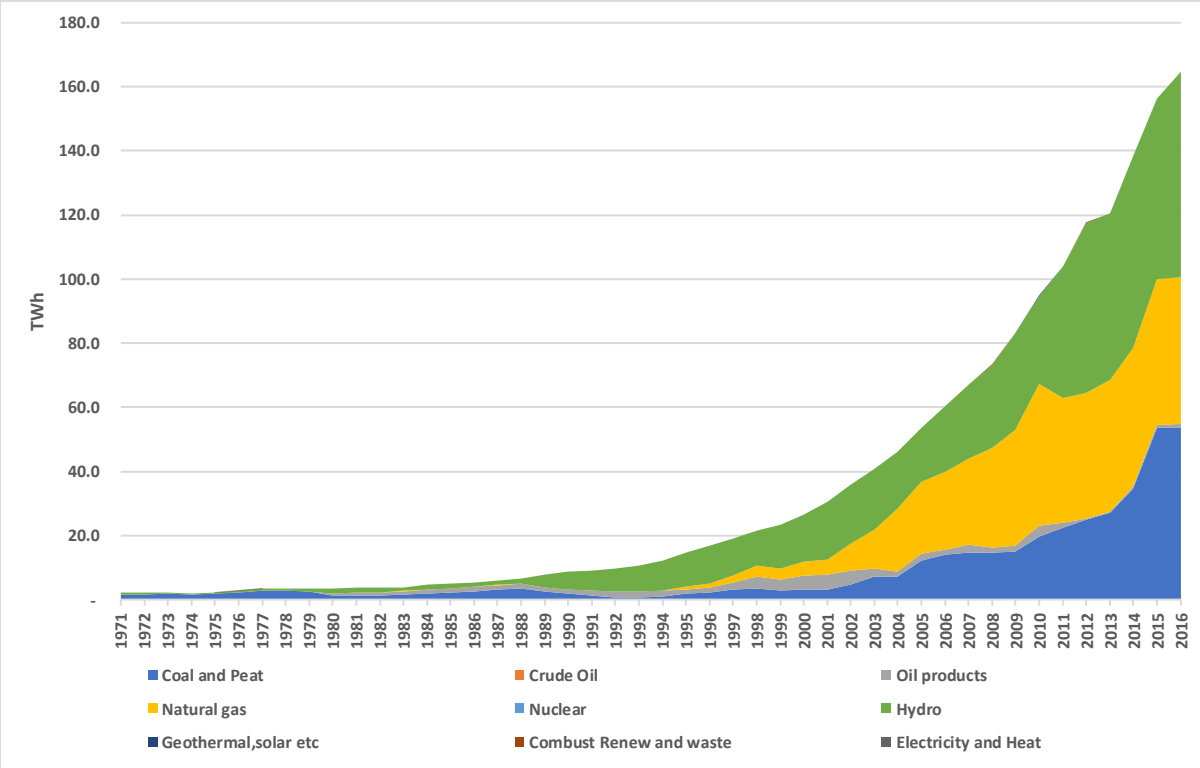

Source: BP Statistical Review of World Energy

In terms of the consumption by sector, transport, not surprisingly, is dominated by oil, while industrial demand is largely made up of electricity and coal, with the latter being particularly prevalent in the iron and steel sector. Meanwhile residential demand is increasingly reliant on electricity as the country moves towards its target of 100 per cent electrification and the phasing out of the use of traditional biomass.

Indeed, the electrification of Vietnam and the demand for energy in the power sector is the main story of the energy economy in the country. Power generation accounts for almost half of total primary energy

demand, and Figure 99 shows both the growth of electricity production and demand since 2000 and also of the fuels used to generate it. Electricity demand has grown by an average of 12 per cent per annum since 2000 (increasing by a factor of almost 10 times over the period) and the mix of fuels has also changed considerably. Oil, having been important in the early days, has now almost completely disappeared, but hydro, another early fuel, has continued to remain vital and still accounts for 39 per cent of the total fuel input. Gas increased in importance in the early 2000s as new indigenous sources of supply were discovered and brought online, but as these have matured so the country has turned to another source of indigenous fuel, coal. As a result, the shares of coal and gas are closely matched at 28 per cent and 33 per cent respectively, reflecting the competition between them, while other renewables account for less than 1 per cent at present.

**Figure 99: Electricity output by fuel in Vietnam (2000-2016)**

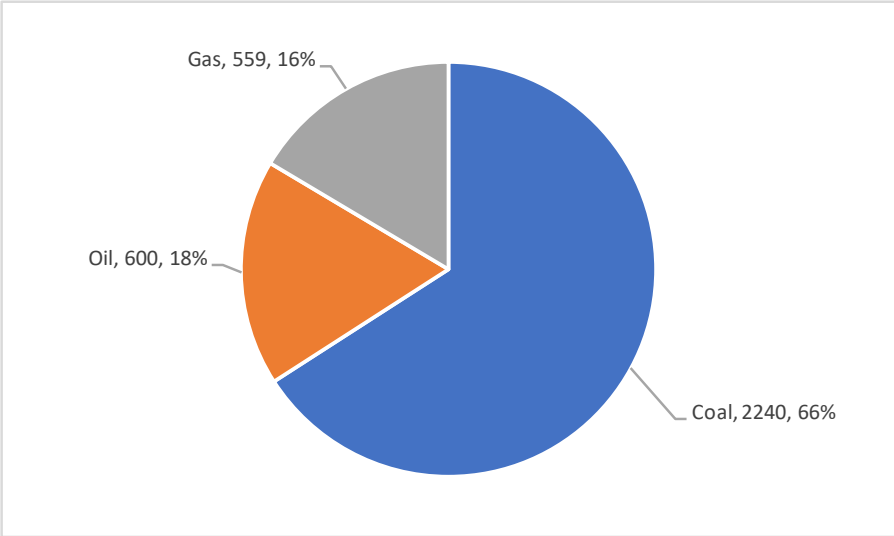



Source: IEA

This balance reflects that state of Vietnam's domestic energy resources and production, as shown in the next three charts. Figure 100 shows the country's current proved reserves of hydrocarbons, underlining the importance of coal which accounts for two thirds of the total and has a reserves life of almost 90 years at current levels of production. Oil is in second place, with 4.4 billion barrels of reserves (600mtoe), while Vietnam has an estimated 650bcm of gas reserves (560mtoe) which is equivalent to a reserve life of around 67 years and provides some hope for future upside in production.[184]

[184] APEC Energy Demand and Supply Outlook, 7th Edition, Volume 2, 2019, APEC Energy Working Group, pp.417-436

**Figure 100: Vietnam's hydrocarbon reserves by fuel (2018, mtoe)**

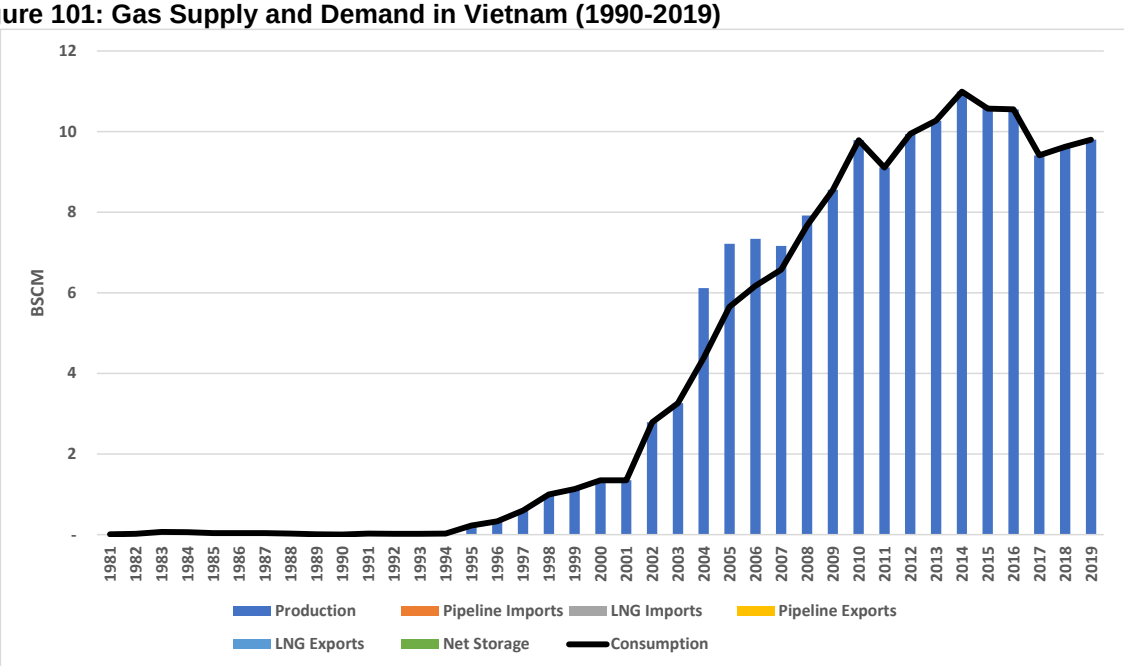



Source: APEC

Despite these indigenous resources, however, the country has moved overall from being a net exporter to a net importer of fuel. Production of oil has gone into decline since the early 2000s while coal supply appears to have peaked, at least for the time being. As a result, both oil and coal imports are now rising rapidly, with total combined imports reaching 23 mtoe in 2018, equal to more than one quarter of total primary energy demand (including hydro).

As far as the gas sector is specifically concerned, though, production has continued to rise, albeit at a slower rate over the past few years, and to date this rising production has been the catalyst for any growth in demand. As can be seen in Figure 101, total demand in 2018 reached 9.7bcm, slightly down from a high of 10.3bcm in 2015 but still five times higher than the level in 2000, underlining the growth in the use of the fuel. For the future, though, the Vietnamese authorities are keen to continue their policy of matching sources of supply, whether indigenous or imported, with specific demand centres, because as yet there is no integrated pipeline infrastructure which links the whole country in one grid.

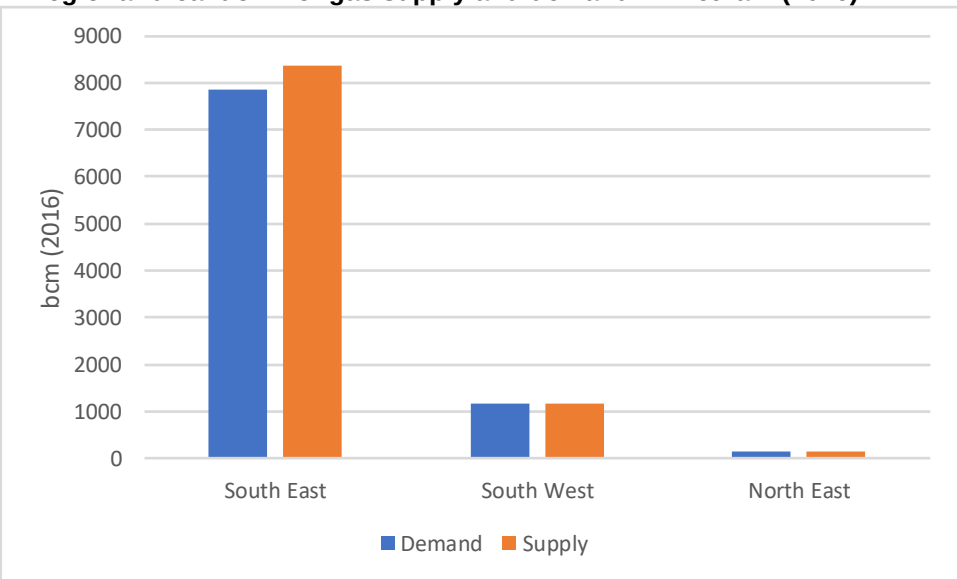
**Figure 101: Gas Supply and Demand in Vietnam (1990-2019)**




Source: IEA

This fact is underlined in Figure 102 which shows a regional breakdown of gas supply and demand. It is clear that the majority of gas is consumed in the south of the country, with gas having historically been produced in large extent in the Cuu Long and Nam Con Son Basins offshore the south-east of the country. Significant reserves also exist in the Song Hong Basin (offshore the north-central region) and also in the Malay-Tho Chu Basin (in the south-west), and indeed the latter is expected to make an increasing contribution as further development of the sector progresses.

**Figure 102: Regional breakdown of gas supply and demand in Vietnam (2016)**



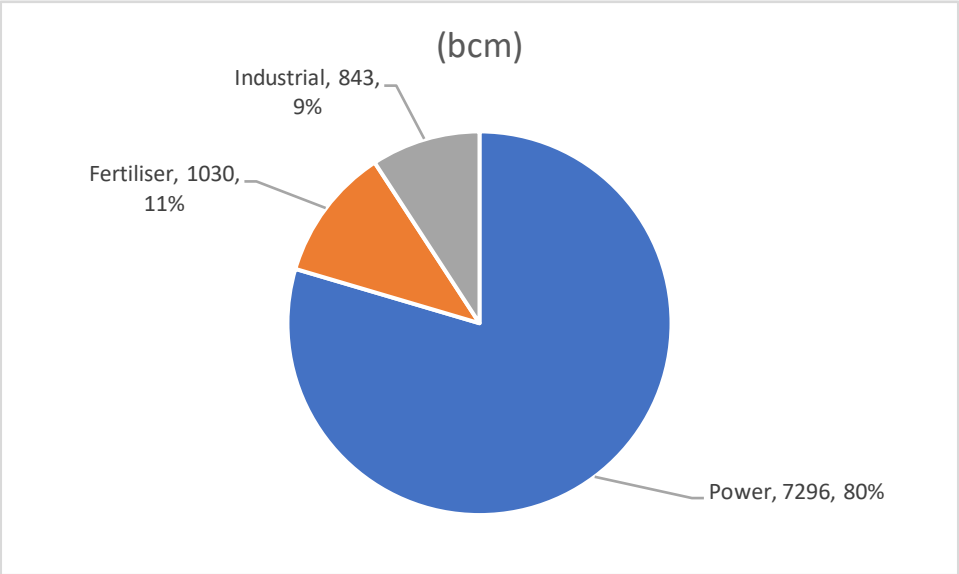

Source: World Bank[185]

48 gas fields are currently in production and a further 15 are planned for development across the four basins mentioned above, with the major active fields including Bach Ho, which started production in 1986 in the Cuu Long basin, Lan Tay-Lan Do (2002), Rong Doi (2006), and Hai Thach-Moc Tinh (2013) in the Nam Con Son basin and PM3-CAA (2007) in the Malay-Tho Chu basin. PetroVietnam is the key domestic actor in these fields but international players are its partners in a number of Production Sharing Contracts (PSCs). The key companies involved from overseas are Gazprom, Rosneft, Mitsui, METI, KNOC, PTTEP and ONGC.[186]

From a demand perspective the importance of the power sector cannot be understated, as shown in Figure 103. It accounts for 80 per cent of total gas consumption and will continue to be key in future as coal is likely to be difficult to displace in many industrial processes due to the capital that has already been committed and the competitive price of the fuel. New industrial demand for gas may be found in the fertiliser and chemical sectors, but in general it will be further expansion of gas-fired power that drives the market in Vietnam.

[185] Vietnam: Maximising Finance of Development in the Energy Sector, 2018, World Bank Group
[186] Detail from PetroVietnam, cited in "Vietnam: Roadmap for Natural Gas Market Development", June 2017, World Bank and Intelligent Energy Systems (IES)

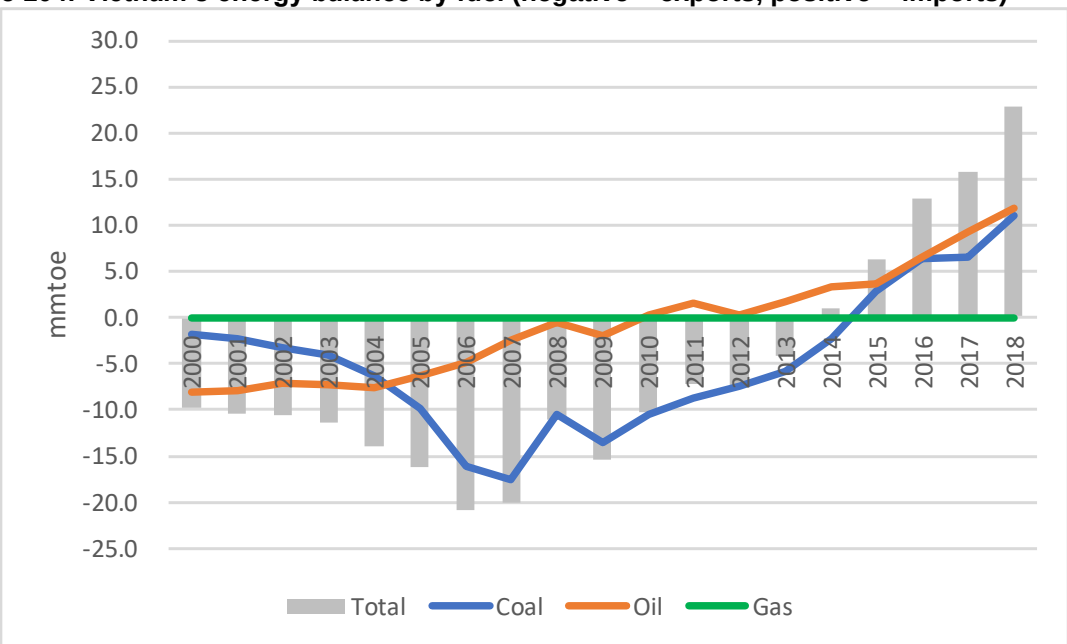
**Figure 103: Sources of Gas Demand in Vietnam (2016)**




Source: Vietnam Ministry of Industry and Transport

As a result, the attractions of gas not only as a cleaner hydrocarbon but also as one where to date supply has matched demand are becoming clearer. As will be discussed below, it is unlikely that this balanced position can be sustained for much longer, and the start of imports is anticipated in the 2020s, but nevertheless the supply deficits in coal and oil argue for greater use of gas and also, of course, for the development of indigenous renewable energy.

**Figure 104: Vietnam's energy balance by fuel (negative = exports, positive = imports)**




Source: BP Statistical Review of World Energy, Author's Analysis

## Government Policy and Regulation

The key institutions which control the gas sector in Vietnam are the Prime Minister's Office, which has direct oversight of the entire energy industry, the Ministry of Industry and Trade (MOIT), which has specific responsibility for managing the overall strategy and planning for the energy industry, and the General Directorate of Energy, which assists the MOIT to implement key tasks. The key corporate actor

in the sector is PetroVietnam (PVN), whose role stretches from exploration and production through trading, transportation, management of imports and even involvement in some downstream businesses such as power generation and fertilizers. PVN also maintains regulatory control of gas prices and other aspects of the sector, under the direction of the government, and also signs all contracts with foreign and domestic investors in the sector.

The development of the gas market is likely to necessitate some form of liberalisation, as has already happened in the electricity sector, and the government has committed to implementation of changes to the legal and regulatory framework from 2025. Until then, the key energy policies are outlined in the Vietnam Energy Outlook Report, which is produced every two years (most recently in 2019), and more specifically in the Power Development Plan for the electricity sector and the Gas Industry Master Plan for the gas sector.[187] The latter was most recently published in 2016 and outlines both the plans for development of the upstream sector as well as the coordination of future gas production with specific projects, mainly in the power sector, that will consume any increased output. It also lays out the potential for future LNG imports via a set of new receiving terminals that are planned across the country.[188]

Perhaps the most important recent theme of energy policy, though, has been the release of a series of energy and climate policy targets. These include expanding the share of renewable energy in the power sector to 33 per cent (excluding hydro) by 2050, to increase energy efficiency by 8-10 per cent by 2030 and to reduce emissions by 20-30 per cent by 2030 and by 45 per cent by 2050, as part of a green growth strategy.[189] While these strategies can clearly benefit gas versus coal they also re-emphasize the importance of growth in renewables as the key priority over the next 30 years.

### *Gas Infrastructure*

Vietnam's gas sector currently consists of a number of isolated markets in the south-east, south-west and north/central regions. Pipelines come from offshore fields to specific industrial and power sector customers, but there are currently no interconnections between the regions themselves. There do not appear to be any significant plans to alter this situation in the near term, and as such the major infrastructure development plans concern the construction of LNG import terminals in anticipation of demand exceeding supply in the relatively short-term (see below).

**Table 9: Vietnam's potential LNG receiving terminals**

| Name | Location | Start | Capacity (MTPA) | |
|---|---|---|---|---|
| | | | *Initial* | *Final* |
| Thi Vai | South East | 2022-23 | 1.0 | 3.0 |
| Son My | South East | 2023-2035 | 3.0 | 9.0 |
| Tien Giang | South East | 2022-25 | 4.0 | 6.0 |
| SW LNG | South West | 2022-25 | 1.0 | 2.0 |
| Thai Binh FSRU | North | 2026-30 | 0.2 | 0.5 |
| My Giang | Central | 2030-35 | 3.0 | 3.0 |
| Cat Hai | North | 2030-35 | 1.0 | 3.0 |
| | | | **13.2** | **26.5** |

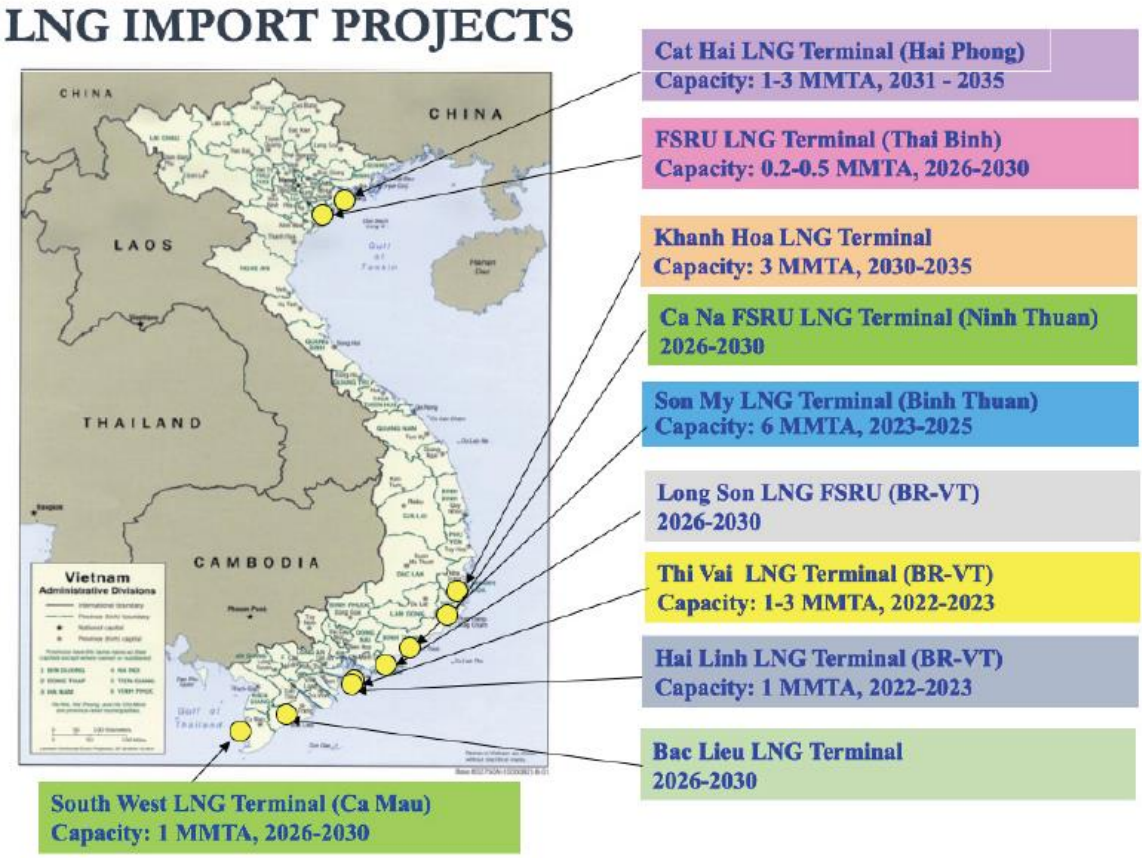
Source: Vietnam Gas Master Plan

[187] Vietnam Gas Industry Master Plan, prepared by Department of Oil, Gas and Coal, Ministry of Industry and Trade, Vietnam sourced from http://49.212.237.197/country/docs/4_CPJ-5-18_MOIT.pdf

[188] See "Vietnam: Roadmap for Natural Gas Market Development" prepared by IES and the World Bank in 2017 sourced from https://ppiaf.org/documents/5572/download?otp=b3RwIzE1NTY5ODM5NzE=

[189] EREA & DEA Vietnam Energy Outlook Report 2019 (2019), pp.14-15

**Figure 105: Vietnam Proposed LNG Import Terminals**




Source: Vietnam Gas Master Plan[190]

The Vietnamese authorities are already exploring the options for development of 7 LNG receiving terminals, as outlined in Table 9. A number of the projects have two or three stages and can therefore be adapted to meet actual demand as it emerges, but once again the overall plan is to match receiving capacity with one or more end users. As an example, the construction of the most imminent plant, Thi Vai, was started in October 2019 and will be built by Samsung C&T at a cost of $180mm and will be located 70km south of Ho Chi Minh city, where it will supply the new Nhon Trach power plant. Meanwhile the Son My terminal, whose first of three phases is expected to be online in 2023 will be linked to the 2GW Son My 1 power project managed by EdF. The receiving terminal may be developed in partnership with US company AES Corporation, after the signing of a memorandum of understanding during President Trump's visit to Hanoi in November 2018. Overall, though, it is clear that plans are being made for a gradual expansion of LNG receiving capacity which could satisfy the highest demand figure outlined in Figure 106 but which could also be adjusted down if either demand fails to materialise or indigenous supply exceeds expectations.[191]

[190] Vietnam Gas Industry Master Plan, prepared by Department of Oil, Gas and Coal, Ministry of Industry and Trade, Vietnam sourced from http://49.212.237.197/country/docs/4_CPJ-5-18_MOIT.pdf
[191] Vietnam Gas Industry Master Plan, prepared by Department of Oil, Gas and Coal, Ministry of Industry and Trade, Vietnam sourced from http://49.212.237.197/country/docs/4_CPJ-5-18_MOIT.pdf

## Supply and Demand Projections

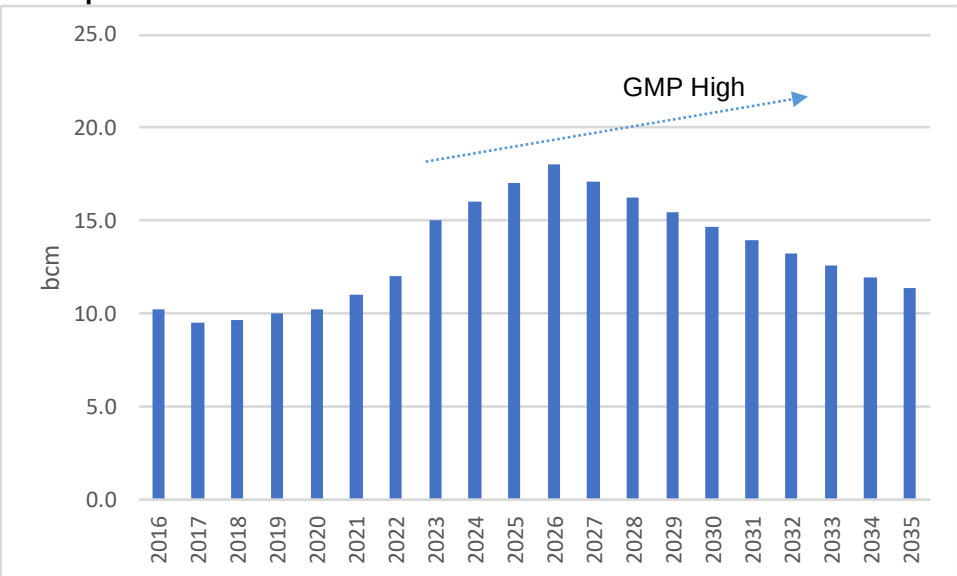
### Production

Looking to the future, then, it is important to assess the potential of indigenous gas production, as this has historically led demand, and also to understand the willingness of the Vietnamese government to approve power projects linked to specific LNG import projects. The Gas Master Plan (GMP, discussed above) can provide some key indicators, but a more realistic assessment of the shape of domestic gas production is also required to calculate the likely need for LNG imports.

In terms of production, the GMP sees a growing level of output through to 2035, from around 10 bcm in 2018 to 13-19 bcm by 2025 and 17-21 bcm by 2035. This optimism is based on a number of new fields that have already been identified, with the most important being Ca Voi Xanh and Block B. The former is expected to commence output in 2023 and to produce 6 bcma at peak from 2025 while the latter was anticipated to take FID in 2020 (although this may be delayed by COVID-19) and to reach a plateau of just under 4 bcma in the 2030s. The expansion of the existing Su Tu Trang field in the south-east region is expected to add another 2.5 bcma by the mid-2020s, while a selection of 10 other small fields is estimated to have a productive capacity of just over 7 bcma, which could be reached by 2035.

However, although the GMP sees consistent growth over the next 15-20 years, a more conservative assessment has been suggested in the Energy Outlook Report for Vietnam published by the Vietnamese Ministry of Industry and Trade and the Embassy of Denmark.[192] This suggests that production may rise until the middle of the 2020s before possibly going into decline if some of the more speculative gas resources are not eventually developed. This can provide a lower production case, as shown in Figure 106 where it is compared to more bullish outlooks from the GMP.

**Figure 106: Gas production forecast for Vietnam**




Source: Author's Estimate, Energy Outlook for Vietnam

### Demand

On the demand side, growth in the power sector will clearly be a key driver. Under the government's energy plan to 2035 electricity production is expected to almost double to reach 388TWh, with total power generating capacity set to be expanded by 80GW. Almost half of this (38GW) will be coal-fired as the country seeks to develop more of its coal reserves and increases imports, and the authorities have emphasized that all this new capacity will be made up of super-critical or ultra-super-critical plants

[192] EREA & DEA: Vietnam Energy Outlook Report 2019 (2019)

that can reduce the environmental impact. Furthermore, renewables are expected to make up a much greater part of the mix – solar is forecast to have a 10 per cent share of power capacity by the end of the planning period, with wind having a 5 per cent share and bioenergy just over 2 per cent. However, this still leaves room for expansion of gas-fired capacity, and the GMP anticipates that this will have tripled to 24GW by 2035 from just over 8GW today.

In particular new gas field developments are being tied to specific power projects, with one example being the Ca Voi Xanh (Blue Whale) project that is being operated by ExxonMobil and PetroVietnam. Gas reserves will be developed offshore, with peak production of 6 bcma being piped to shore, processed and sent to fuel four power plants with a total capacity of 3GW which will provide power for the city of Hanoi and surrounding regions. A final investment decision was expected in 2020 with first gas to be produced in 2023, providing the first major production and consumption in the Central Region of Vietnam. However, the boundary disputes with China may cause delays and ExxonMobil may, reportedly, be rethinking their involvement[193].

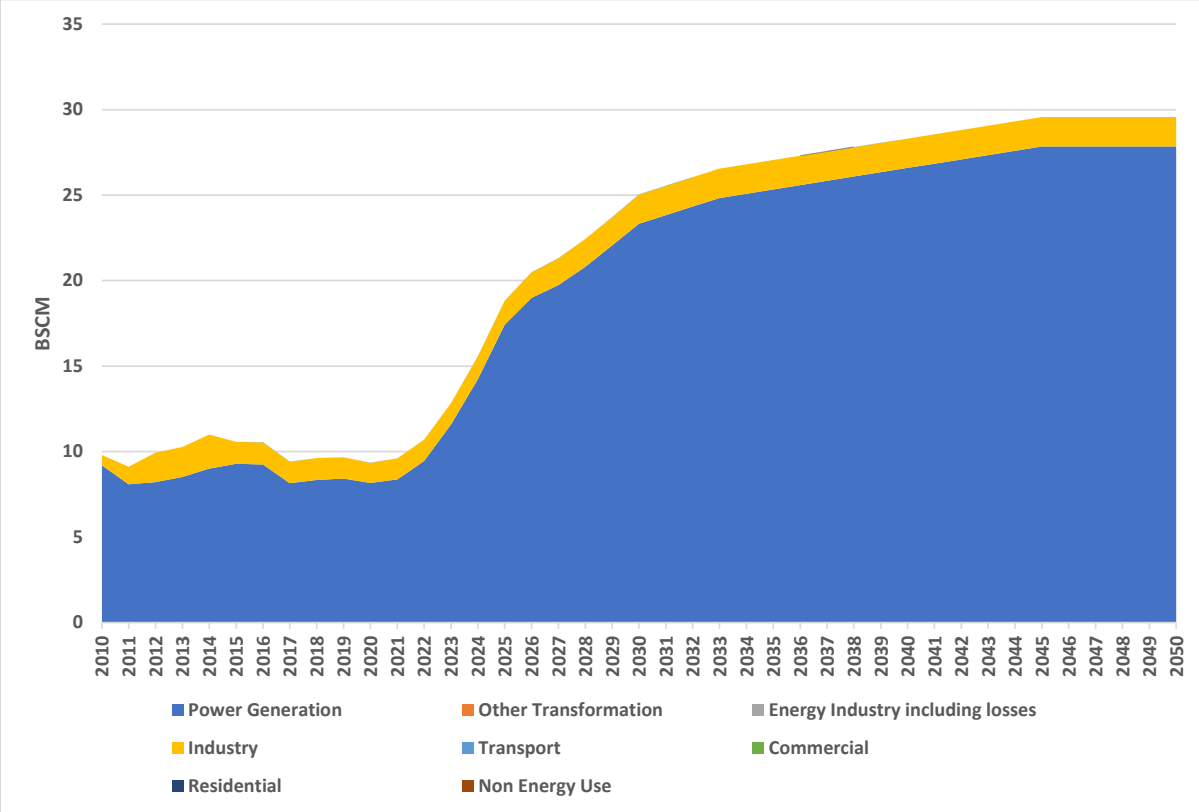
Other gas-fired capacity is expected to be built in the more gas prone south of the country. Vietnam's Power Development Plan envisages an additional 8.5GW of gas-fired power capacity in the South East region by 2030 and a further 2.2GW in the South West, with the latter being supplied by the new offshore development in Block B while the latter will be supplied from gas produced at smaller offshore fields and also from LNG imports. Overall, it is expected that gas demand from the power sector will grow from around 8.6 bcm in 2015 to more than 22 bcm by 2035.[194]

The other key driver of gas demand growth will come from the fertilizer sector, where the industry is being transformed as the Vietnamese government seeks to improve farming practices and make them more organic. The sector is expected to double in size by the mid-2020s, providing significant scope for an increase in gas demand as the Vietnamese agricultural sector seeks to satisfy growing domestic demand and to increase exports. In addition, a move away from chemical fertilizers to more organic products should also help encourage gas demand, which is heavily used in the manufacturing process. Overall, it is estimated that gas demand in this sector could rise by a factor of 6 times to reach 6.5 bcm by 2035.

Total gas demand is therefore estimated to have the potential to rise from around 10 bcm in 2018 to 31 bcm by 2035 in the most optimistic case, with a less bullish assessment being that consumption might only reach 23 bcm if gas supply is not available in sufficient quantities. However, if supplies of domestic and imported gas can be secured, there seems to be little doubt that demand can be generated in the power sector especially, but possibly also the fertilizer and industrial sectors, with only the residential sector being apparently monopolised by electricity. The Base Case gas demand is shown in Figure 107.

[193] https://asiatimes.com/2019/09/all-the-reasons-exxonmobil-may-leave-vietnam/
[194] APEC Energy Demand and Supply Outlook, 7th Edition, Volume 2, 2019, APEC Energy Working Group, pp.417-436

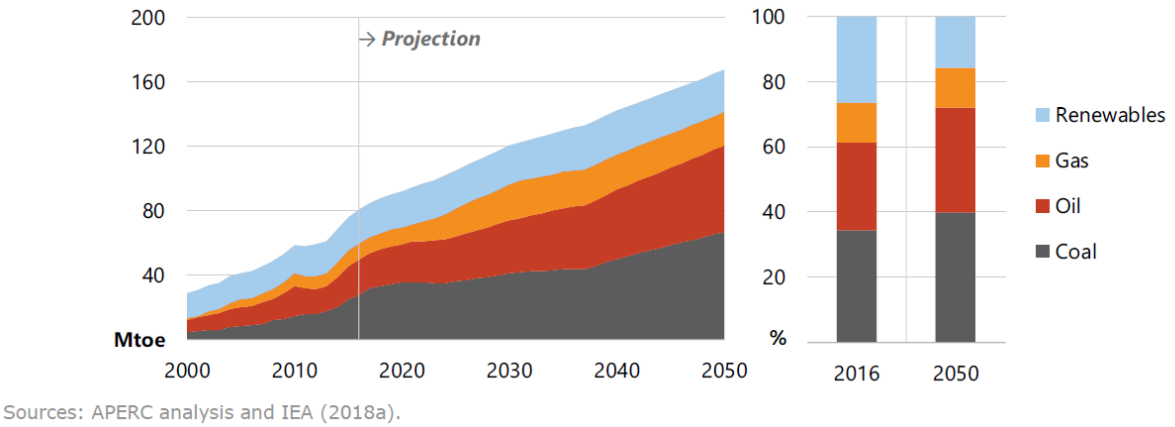
**Figure 107: Vietnam Base Case Demand Projection**




Source: Author's Analysis, Vietnam Gas Master Plan

An interesting point of comparison can be found in the results of the APEC Energy Demand and Supply Outlook,[195] where the Business as Usual (BAU) scenario sees gas demand rising to 22.6 Mtoe (26.3 bcm) by 2035 – in other words very much in line with our base case forecast above. APEC see power generation as the key driver of demand growth, with gas supplying 19.6 Mtoe (23bcm) by 2035 in this sector as it competes with coal as the main hydrocarbon input (coal supplies 20.8 Mtoe by 2035). Industry then accounts for the remainder of gas demand.

**Figure 108: APEC BAU Outlook**

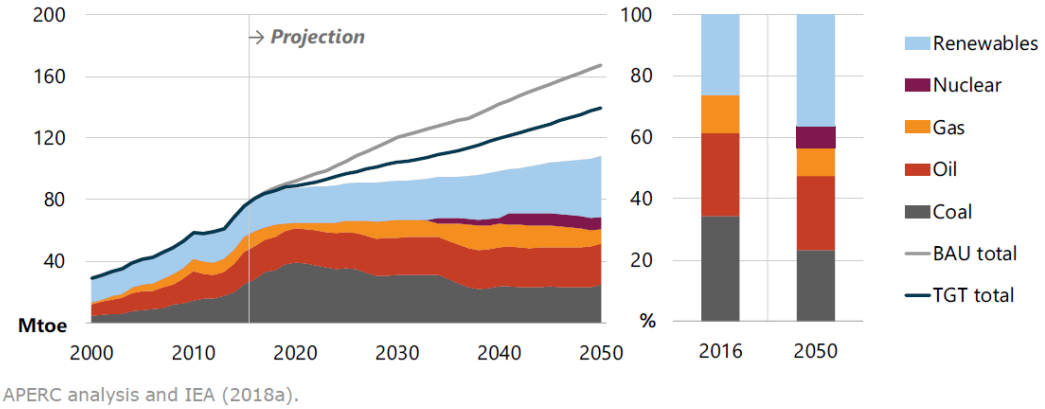



Sources: APERC analysis and IEA (2018a)

[195] APEC Energy Supply and Demand Outlook, 7th Edition, Volume 2, pp.417-436

Interestingly, APEC also produce a “2 Degrees C” (2DC) scenario which assesses how energy demand might change to meet climate change goals. In Vietnam’s case the answer is that overall demand in 2035 would decrease very significantly thanks to a huge increase in energy efficiency, such that total primary energy demand would be lower by 26 per cent at 131Mtoe in the BAU case compared to 97Mtoe in the 2DC case. In the power sector renewables output would jump sharply, and although coal would be the fuel most badly affected, gas demand would also be significantly lower at 10.7Mtoe (12.5bcm) although it would rise by 2040 to 15.5Mtoe (17.7bcm). Nevertheless, this would be well below the low case scenario above, highlighting the risks for gas in Vietnam should the country develop an aggressive environment-based energy strategy.

**Figure 109: APEC 2DC Outlook**

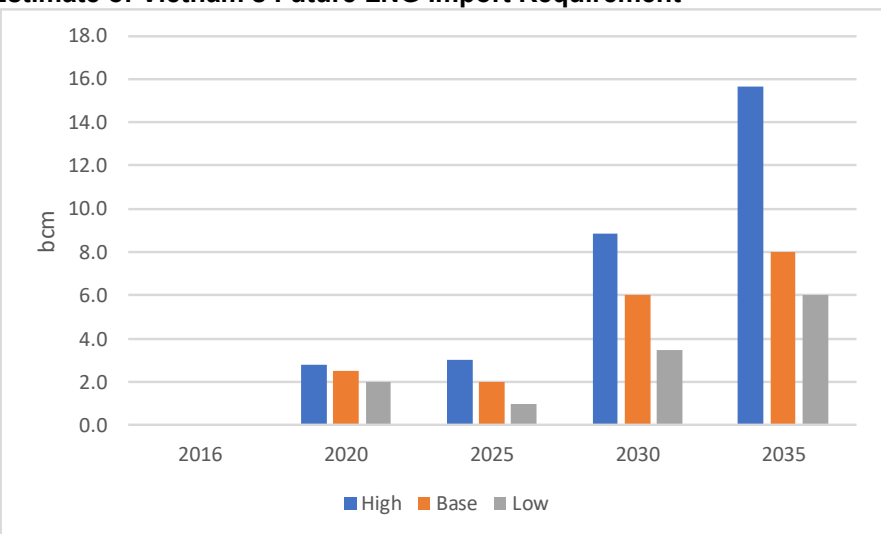



Sources: APERC analysis and IEA (2018a)

## Outlook for LNG imports

The final question, then, is where this leaves the outlook for LNG imports given the various supply and demand scenarios. If one takes the Base Case scenario for demand and applies three production cases – a “proved” case which only includes existing production and the two new fields that have specific development plans (Blue Whale and Block 3), a probable case which is a mid-range estimate from the GMP, and a possible case, which is the highest production forecast from the GMP – then it is possible to create a range of LNG import scenarios which are shown in the figure below. It clearly shows that gas imports will be needed in all cases, with the range of requirement by 2035 ranging from 6 to 16bcm (4.4 to 11.5 million tonnes of LNG).

**Figure 110: Estimate of Vietnam’s Future LNG Import Requirement**

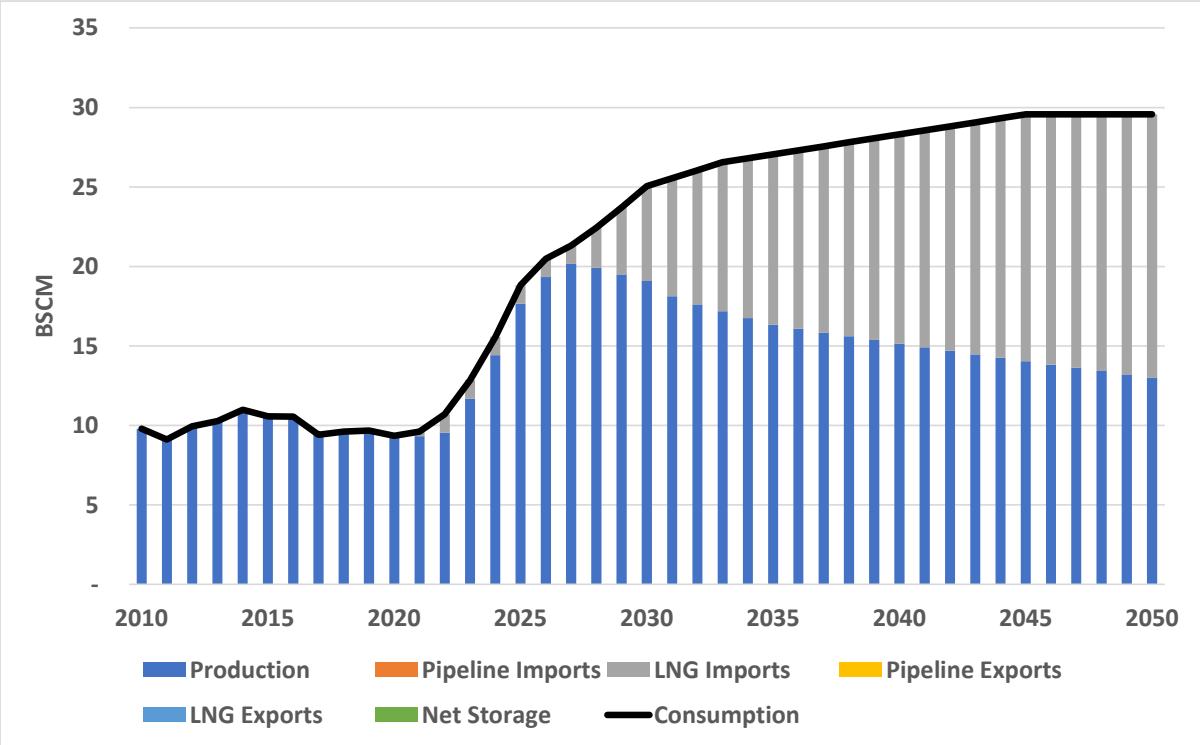



Source: Author’s Estimate

Interestingly PetroVietnam has already signed some agreements for LNG imports from the early 2020s. Its subsidiary PV Gas has a 20-year contract with Gazprom Marketing and Trading to purchase 1 mtpa for 20 years from 2021 delivered to the Thi Vai terminal, while it has also signed an MoU with Shell to supply LNG to the Son My terminal from the mid-2020s. It remains to be seen whether these expectations are fulfilled, as there is a tendency for projects in Vietnam to be delayed (Thi Vai was originally scheduled to be online by 2017),[196] but it certainly does now seem that necessity will push through development of these two terminals.

Our base case supply and demand scenario is shown in Figure 111.

**Figure 111: Vietnam Base Case Supply and Demand Projection**




Source: IEA, OIES Estimates, Nexant World Gas Model

The period through to the late 2020s reflects the base or low case for imports but with the need to grow electricity generation, the scope for LNG imports increases significantly as the surge in production begins to tail off and actually begins to decline.

## Conclusions

Vietnam's economy, and therefore its energy demand, are growing fast, and the country's urbanisation is also encouraging replacement of traditional biomass consumption with use of electricity. The favoured fuel inputs for power generation are hydro and coal, but the former has little room for further growth while the latter, although cheap and plentiful domestically, is harmful to the environment. A major push is being made to increase renewables output, but as this is from a very low base there seems to be little doubt that gas demand will grow significantly over the next 20 years, as it will compete with coal in the power sector. The key drivers will be the availability of domestic supply and the ability to create import opportunities for LNG.

The Vietnamese authorities clearly anticipate this outcome and plans for new LNG receiving terminals have been made. The first could be online within three years, and subsequent projects are likely to be

[196] LNG World News, 23 June 2014, "Shell to supply LNG to PV Gas"

linked to new power plants or to an expanding fertilizer sector, where gas demand is also expected to grow. Although the range of potential LNG estimates is relatively wide, it would certainly seem that at least 5-10mt of new supply will need to be contracted over the next decade, and possibly more if air quality issues become more serious and coal needs to be displaced by a cleaner alternative.

The main risk to gas, as highlighted in the APEC 2DC scenario, is if the government adopts a radical environmental policy based on reducing $CO_2$ emissions. In this case overall energy demand could be as much as 25 per cent lower, and with renewables prioritised in the power sector gas demand in 2035 could be more than halved to around 12.5bcm. This is much lower than our low case forecast above, and we believe that the chance of this outcome is small, but it should be borne in mind by any potential exporters of LNG to the country.

## SUMMARY AND CONCLUSIONS

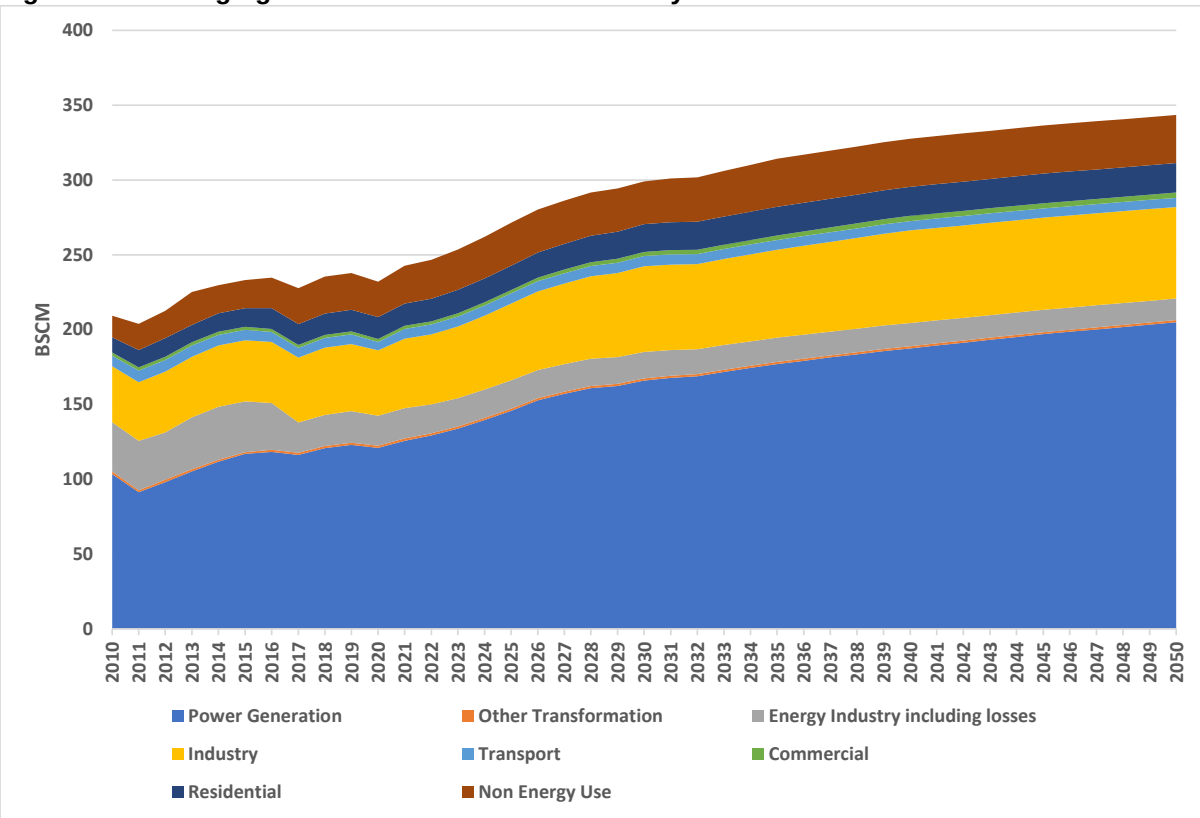
### Gas Demand

Total gas demand in the emerging Asian markets was around 240 bcm in 2019. The 2020s are expected to see a rapid rate of growth to some 300 bcm by 2030, but thereafter growth slows to reach 325 bcm by 2040 and just over 340 bcm by 2050. These projections assume a largely "business as usual" scenario, with only slow progress towards decarbonisation. A policy change to support decarbonisation more strongly in these markets could turn out to be supportive for gas initially, before leading to a decline in demand, as coal is rapidly phased out.

It was noted in the Introduction and also throughout the country sections, that there is considerable uncertainty in relation to the growth of gas demand. Much of this relates to the competition with coal in the power sector, but also how gas fares in other sectors, notably the industrial sector, where there remains scope for the displacement of oil products. Following a detailed overview of the "business as usual" scenario, we will return to the uncertainty surrounding gas demand and the consequences for LNG imports.

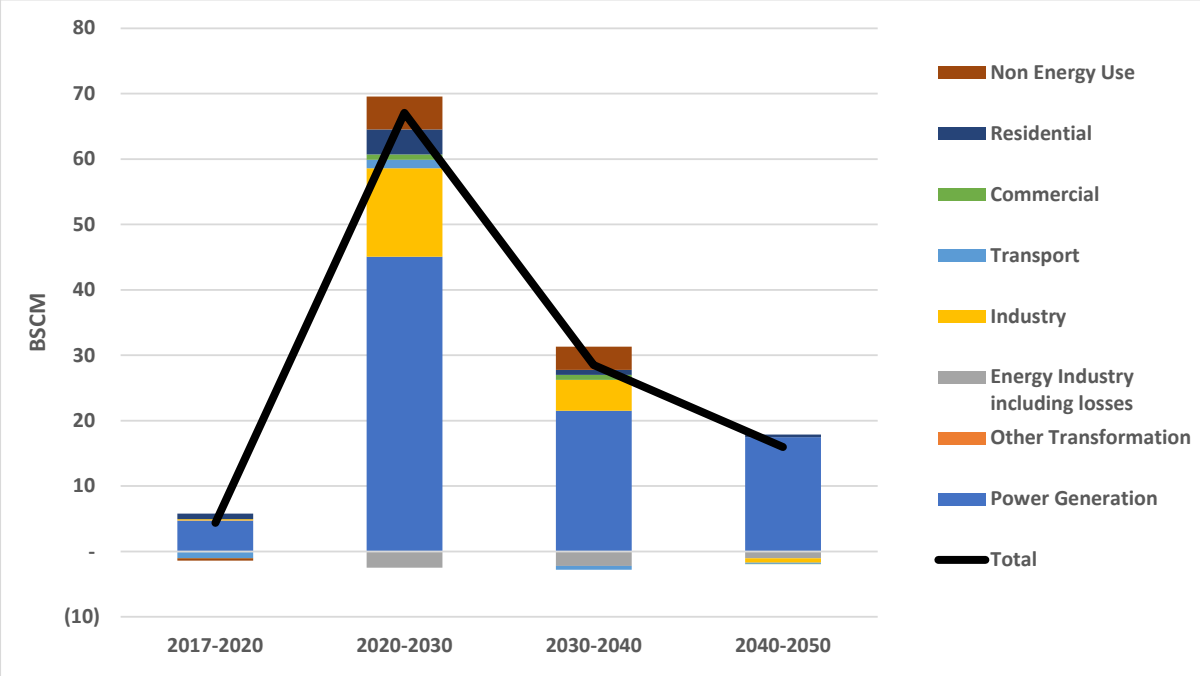
Power generation accounted for half of total gas demand in 2019, and its share increases over time to reach 60 per cent by 2050. Industry (including non-energy use) accounted for some 30 per cent in 2019 and this share is broadly maintained throughout the projection period. Energy Industry use was some 9 per cent in 2019 but is less than half this in 2050, as hydrocarbon production in total is in decline. Other sectors decline slightly in total.

**Figure 112: Emerging Asian Markets - Gas Demand by Sector to 2050**



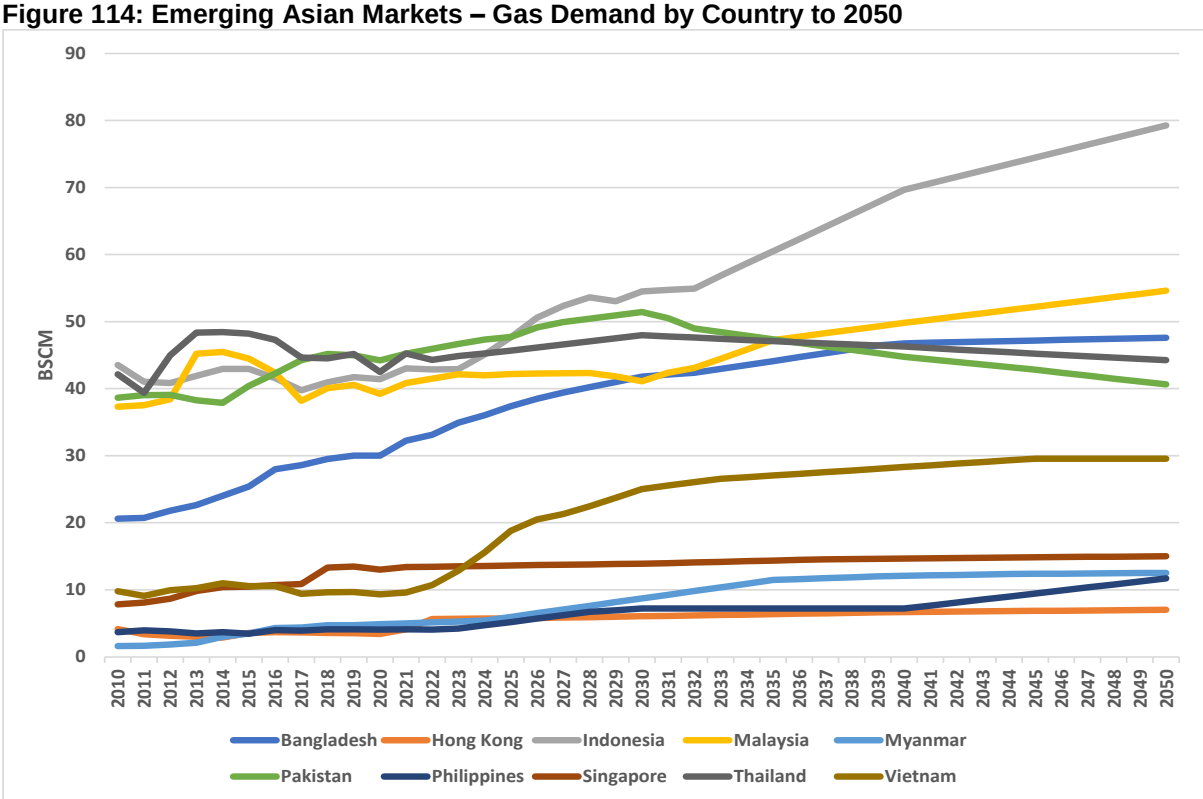

Source: IEA, OIES, Nexant World Gas Model

**Figure 113: Emerging Asian Markets – Change in Gas Demand to 2050**




Source: IEA, OIES, Nexant World Gas Model

**Figure 114: Emerging Asian Markets – Gas Demand by Country to 2050**



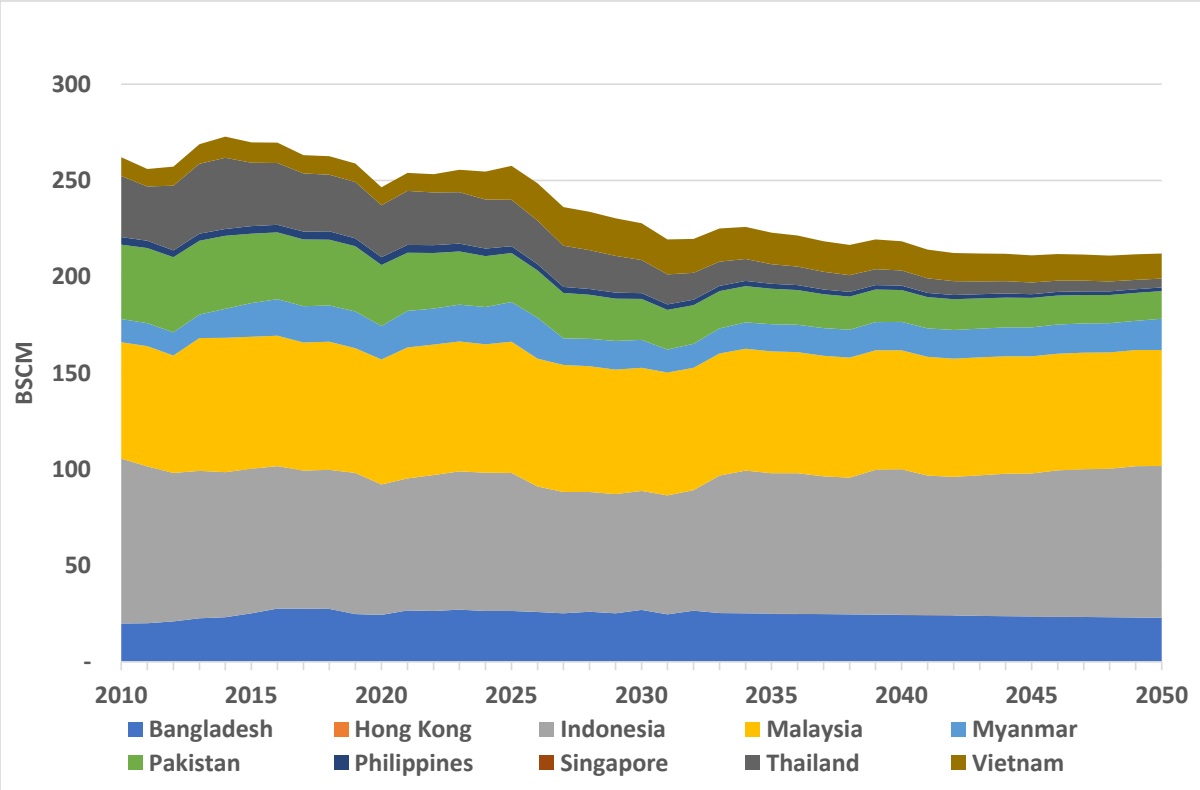

Source: IEA, OIES, Nexant World Gas Model

At the individual country level, the countries with long term growing demand include Indonesia, Malaysia (post 2030), Bangladesh, Vietnam and Myanmar. Pakistan has some growth up to 2030, as unsatisfied demand is met, but thereafter declines, while Thailand is in decline post 2030. Little growth is expected in Singapore, and relatively small growth in Hong Kong and Philippines.

## Production

Overall gas production is in decline. From a level of some 260 bcm in 2019, it declines to 230 bcm in 2030, 220 bcm in 2040 and 210 bcm in 2050. There are, however, significant differences between countries. Bangladesh, Indonesia, Malaysia and Myanmar have broadly stable levels of production, although production in Indonesia declines in the late 2020s before increasing again in the mid-2030s. Pakistan and Thailand are both in long-term decline and are largely responsible for the aggregate decline in production for the emerging markets as a whole. Vietnam has a short burst of growth from the mid-2020s onwards, before beginning a slow decline from the mid-2030s.

**Figure 115: Emerging Asian Markets - Production to 2050**




Source: IEA, OIES, Nexant World Gas Model

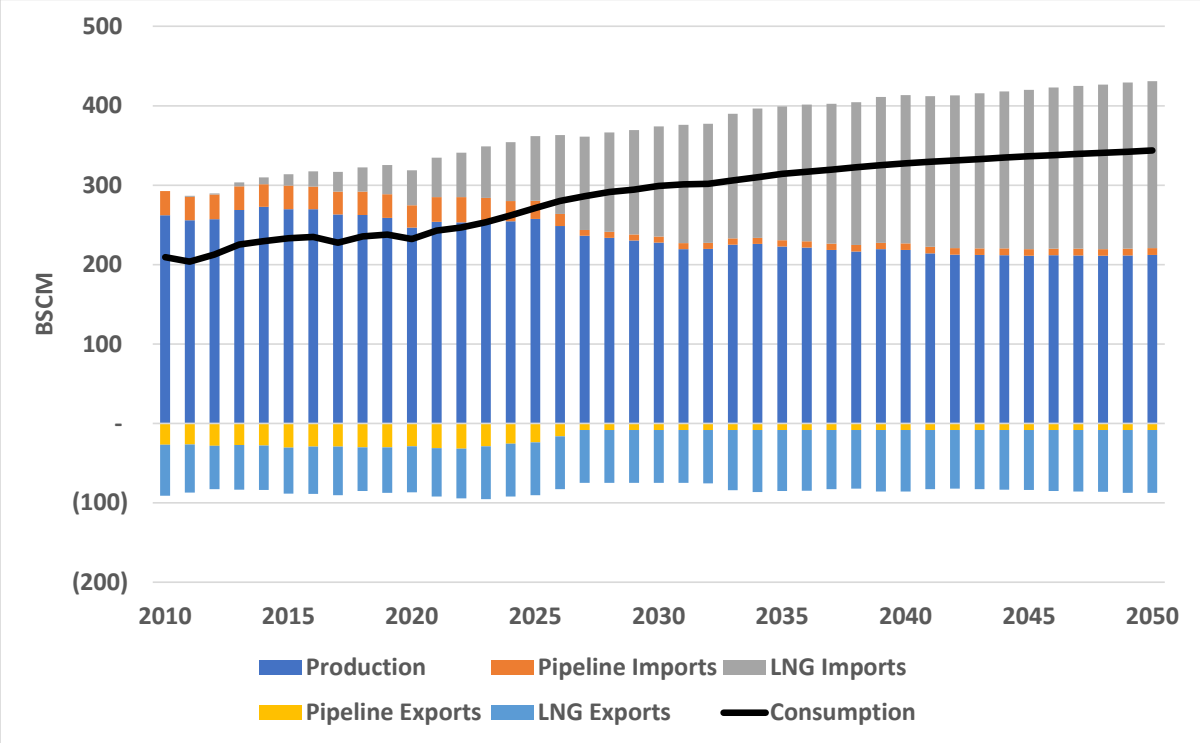
## Supply and Demand Balance

As was noted in the Introduction and in the specific country sections, almost all the pipeline trade is within the ASEAN region, apart from Myanmar exports to China. As contracts end and reserves are depleted, pipeline flows reduce significantly from the mid-2020s onwards. This opens up some space for LNG imports.

With aggregate gas demand increasing and aggregate production declining, the supply gap widens continuously over the period. Those gas producers with largely stable production – Bangladesh, Indonesia and Malaysia – are also those with the largest increases in demand. Pakistan and Thailand are faced with rapidly declining production but relatively stable or even declining demand later in the period. Both sets of circumstances lead to sharp increases in supply gaps.

In Hong Kong, Philippines and Myanmar, the relatively small rise in gas demand and hence supply gap reflects diversification away from other gas supply sources or niche areas of gas demand. Singapore's supply gap grows slowly in line with rising electricity demand.

**Figure 116: Emerging Asian Markets - Supply - Demand to 2050**

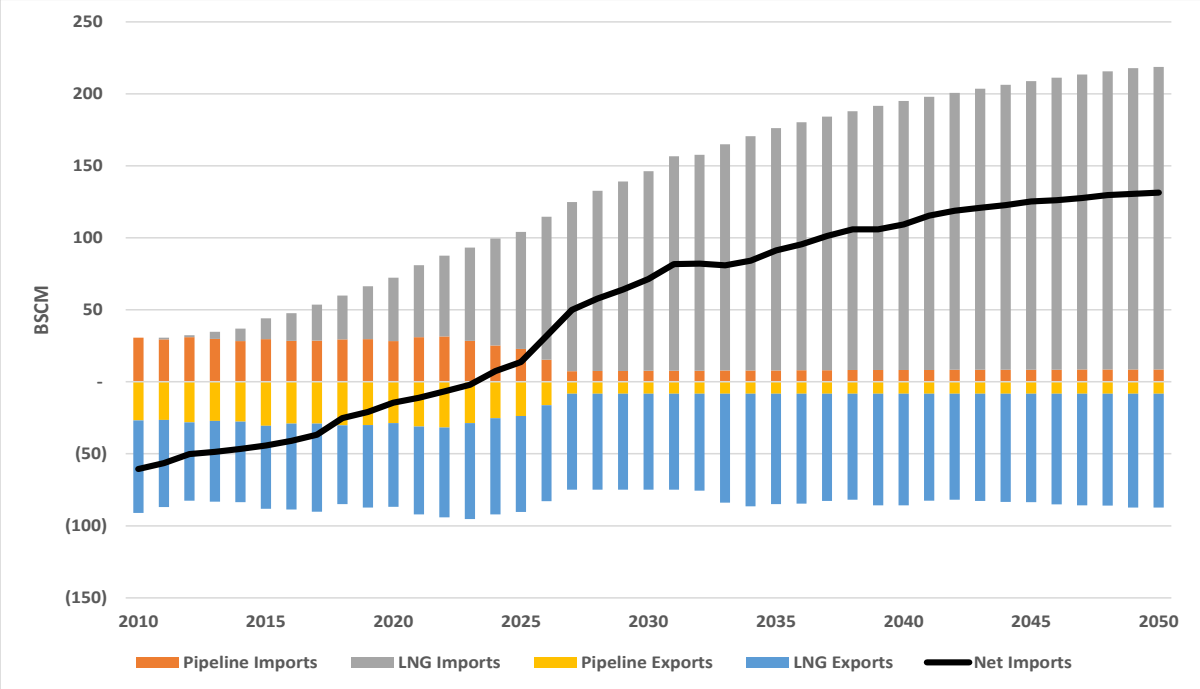



Source: IEA, OIES, Nexant World Gas Model

Total LNG exports from Indonesia and Malaysia are broadly maintained over the period, weakening slightly in the late 2020s. However, particularly in the case of Indonesia, a significant proportion of the LNG trade is intra-country, at least through to 2030.

In 2019, the emerging Asian markets in aggregate were net exporters by some 20 bcma. This changes to net imports of some 70 bcma by 2030, 110 bcma by 2040 and 130 bcma by 2050

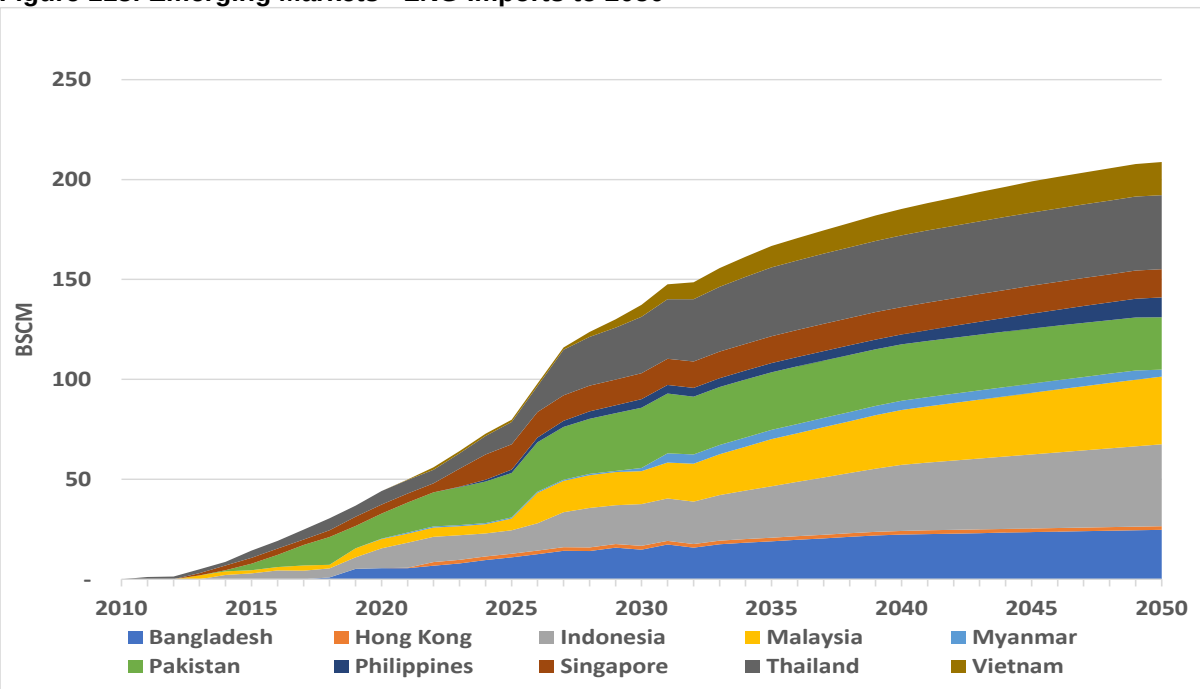
**Figure 117: Emerging Markets - Net Imports to 2050**




Source: IEA, OIES, Nexant World Gas Model

## LNG Imports

**Figure 118: Emerging Markets - LNG Imports to 2050**




Source: IEA, OIES, Nexant World Gas Model

The growth of LNG imports over the period is slightly greater than the change in the supply gap, as pipeline trade declines. LNG imports in 2019 were around 35 bcm, and rise to 140 bcm in 2030, 185 bcm by 2040 and 210 bcm by 2050. The 2020s are the period of strongest growth, which coincides with

the sharpest decline in production and the period of fastest rising demand. There is a particularly sharp surge post 2025, as the pipeline contracts come to an end.

**Table 10: Emerging Markets - LNG Imports to 2050**

| BSCM | 2017 | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|
| Bangladesh | - | 5.5 | 14.8 | 22.4 | 24.7 |
| Hong Kong | - | - | 1.8 | 1.8 | 1.8 |
| Indonesia | 4.3 | 9.9 | 20.9 | 33.1 | 41.0 |
| Malaysia | 2.7 | 4.7 | 16.5 | 27.4 | 33.9 |
| Myanmar | - | 0.1 | 1.6 | 4.6 | 3.5 |
| Pakistan | 10.3 | 12.6 | 30.1 | 28.2 | 26.3 |
| Philippines | - | - | 4.3 | 4.9 | 9.9 |
| Singapore | 2.7 | 4.5 | 13.0 | 13.7 | 14.1 |
| Thailand | 5.0 | 6.8 | 28.3 | 35.9 | 37.0 |
| Vietnam | - | - | 6.0 | 13.2 | 16.5 |
| **Total** | **24.8** | **44.1** | **137.3** | **185.3** | **208.7** |

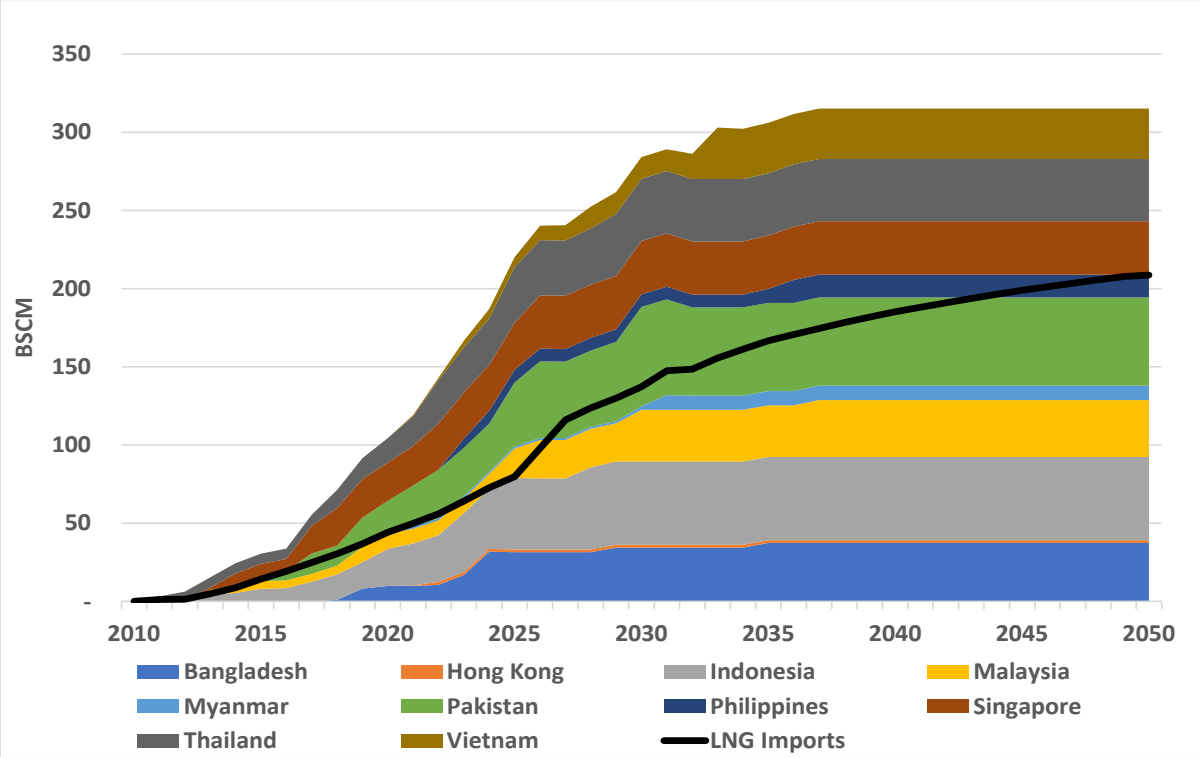
Source: IEA, OIES, Nexant World Gas Model

Pakistan is currently the largest LNG importer in the emerging Asian markets, but is eventually overtaken by Indonesia and Thailand in the 2030s and Malaysia in the 2040s. Bangladesh imports rise to almost the same level as Pakistan's by the end of the period. Growth in LNG imports to Singapore are largely in the 2020s, as pipeline trade declines, while in Vietnam growth comes largely in the late 2020s and early 2030s, as the production growth ends and begins to reverse.

Overall growth in LNG imports from now through to 2040, for the emerging Asian markets, matches the expected growth in China and India LNG imports over the same period, under the latest OIES global gas projections.

The rapid rise in LNG imports requires a significant increase in the regasification infrastructure. Capacity generally increases well in advance of the rise in LNG imports, but as Figure 119 shows, capacity will need to more than double in the next five years. If the required infrastructure fails to get built, then imports could be significantly constrained. Outside of those countries which are yet to become importers – Hong Kong, Philippines and Vietnam, both Pakistan and Bangladesh need to add to their 2019 capacity to meet their expected level of LNG imports in 2023 and 2024 respectively. Indonesia, Malaysia and Thailand are set to exceed their 2019 import capacity in 2026 and 2027. Any material delays in building the regasification infrastructure could constrain the growth of LNG imports.

**Figure 119: Emerging Markets - Regasification Capacity**




Source: OIES, Nexant World Gas Model

## Key Uncertainties

The projections of LNG imports for the emerging Asian markets are a consequence of the difference between two large numbers – demand and production – and, to a lesser extent, changes in intra-regional pipeline trade in the ASEAN region.

There would seem to be somewhat greater certainty on the path of gas production in the key countries, all of which are relatively mature regions. Indonesia overtook Algeria to become the world's largest LNG exporter in 1980 and held on to this title until overtaken by Qatar in 2006[197]. A year later Malaysia overtook Indonesia to become the world's second largest LNG exporter, having been the third largest exporter, behind Algeria since the early 1990s. In 2010, Malaysia and Indonesia were still second and third behind Qatar. While Indonesian LNG exports have declined since 2010, Malaysia was still the world's third largest LNG exporter in 2018, behind only Qatar and Australia, being overtaken in 2019 by the USA and Russia.

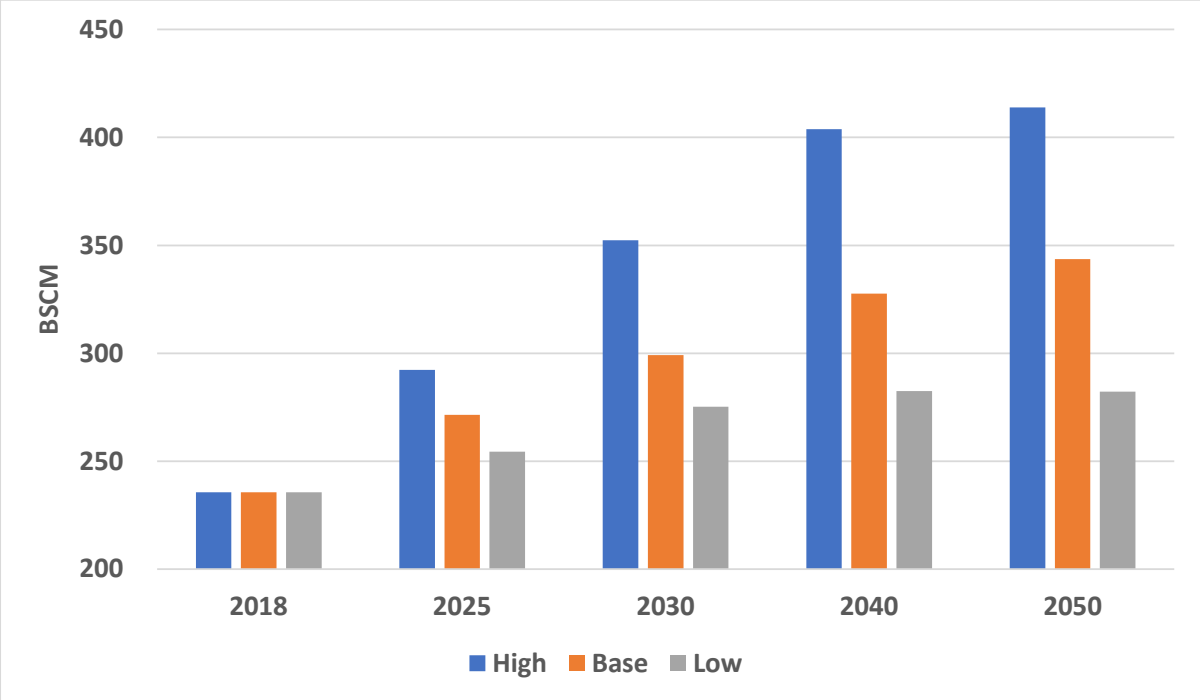
Pakistan has been producing significant quantities of gas since the early 1970s and Bangladesh since the early 1980s. Thailand began ramping up production in the mid-1980s and Myanmar in the late 1990s to export to Thailand. Bangladesh, Myanmar and Malaysia production has now plateaued and Indonesia and Pakistan are in decline. The era of significant new discoveries, certainly economic ones, would appear to be largely over for the emerging Asian markets.

Gas demand, therefore, would appear to be the key area of uncertainty. For each country a high and low case has been considered, largely based on the competition between gas and coal in the power sector and, to a lesser extent, the industry sector. The potential range is not necessarily related to decarbonisation policies but, as has been noted in the individual country sections, coal is expected to

[197] Algeria briefly regained top spot in 1983.

be phased out over time and gas stands to benefit from this, especially if its emissions can be abated through CCS.

**Figure 120: High and Low Gas Demand**

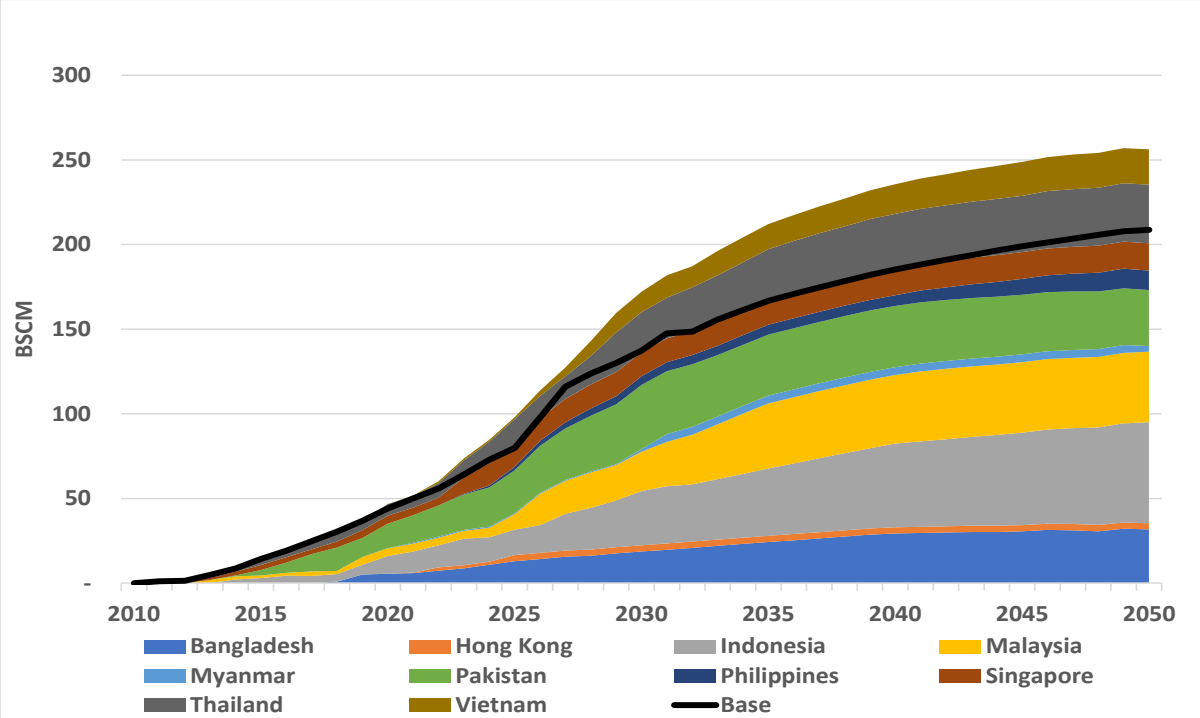



Source: IEA, OIES, Nexant World Gas Model

In the Base Case, gas demand rises by just over 100 bcma through to 2050. In the High Case the increase is some 180 bcma and in the Low Case, demand still increases but only by just under 50 bcma. There is less variation in countries with little or no coal, such as Singapore, while the upside potential for gas is greatest in countries like Indonesia and Malaysia, where there is significant opportunity to displace coal in power especially.

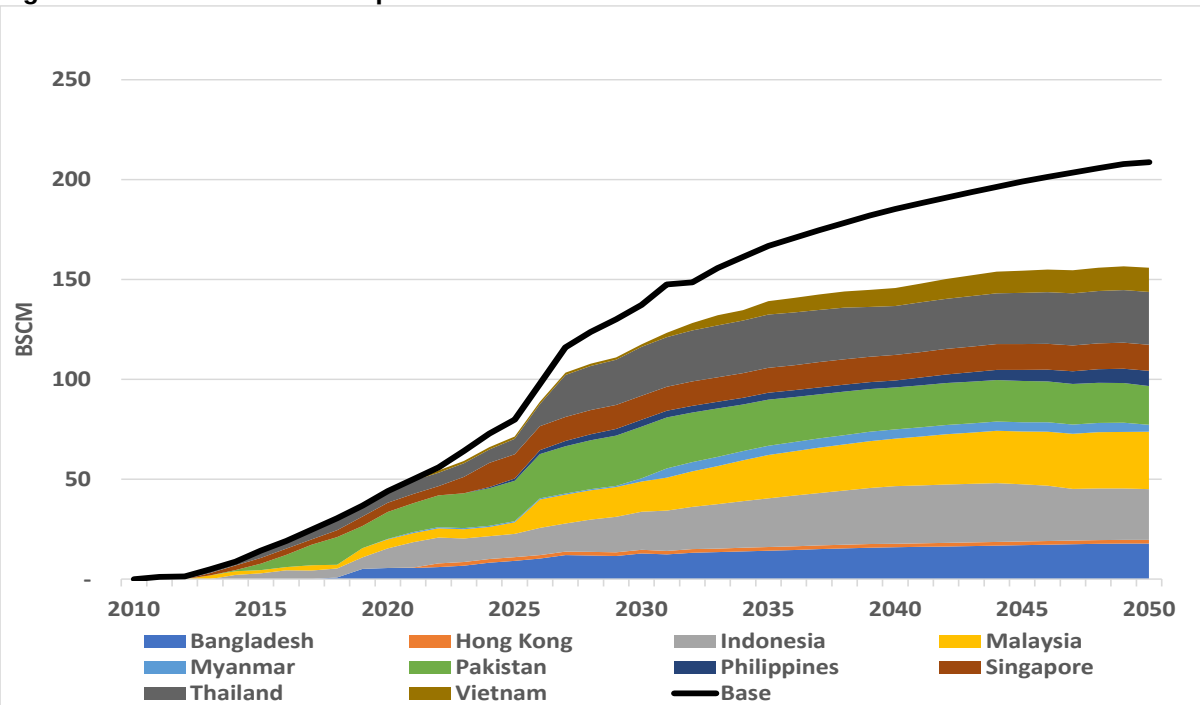
In the High Case, LNG imports reach 170 bcm in 2030, 235 bcm in 2040 and 255 bcm in 2050. This is some 30 bcm higher than the Base Case in 2030, 50 bcm higher in 2040 and 2050. In many countries, the higher demand largely translates into higher LNG imports, except in Thailand where, the higher level of demand also prompts renewed pipeline imports from Myanmar.

**Figure 121: High Case LNG Imports**




Source: IEA, OIES, Nexant World Gas Model

**Figure 122: Low Case LNG Imports**




Source: IEA, OIES, Nexant World Gas Model

In the Low Case, LNG imports reach 120 bcm in 2030, 145 bcm in 2040 and 155 bcm in 2050. This is some 20 bcm lower than the Base Case in 2030, 40 bcm lower in 2040 and 50 bcm lower in 2050. The lower demand, for the most part, translates more directly into lower LNG imports.

There is still significant growth in LNG imports in the Low Case and there remains a requirement for infrastructure investment in order to accommodate the rising LNG imports in almost all countries. The main issue, therefore is how rapid the growth of LNG imports in the emerging Asian markets will be. The range is potentially very wide – 120 to 170 bcm in 2030, 145 to 235 bcm in 2040 and 155 to 255 bcm in 2050. Much of the growth and the wide range is dependent on the growth of gas demand in the power sector. The infrastructure investment required is not only in respect of regasification facilities and gas pipelines, but also in the construction of many gigawatts of gas-fired power plants in these countries to consume the gas. Financing all this infrastructure investment, therefore, is a crucial element in ensuring that gas demand grows.

Possible decarbonisation scenarios have been discussed in some of the country sections, and while no explicit decarbonisation scenario has been considered, it is not clear that rapid decarbonisation would necessarily lead to lower gas demand and hence LNG imports. Early moves to decarbonisation in countries such as Indonesia and Malaysia for example, would likely see a rapid switch away from coal in power (and industry), and, given the growing electricity demand, gas would be well placed to benefit from this, in combination with renewables.

There has been no discussion of gas prices in this paper, with the focus being on volumes. While the competitiveness of gas, in relation to coal and renewables, is a key issue, this was a deliberate omission. Gas pricing in many of the emerging Asian markets remains a complex matter, with the prices of imports not always being passed through into the end user markets, with outright subsidies and cross subsidies being found. Back in 2017, Jonathan Stern noted[198] that,

> "the key to gas fulfilling its potential role as a 'transition fuel' up to and beyond 2030, is that it must be delivered to high-income markets below $8/MMbtu, and to low-income markets below $6/MMbtu (and ideally closer to $5/MMbtu). The major challenge to the future of gas will be to ensure that it does not become (and in many low-income countries remain) unaffordable and/or uncompetitive, long before its emissions make it unburnable".

In the current (August 2020) market environment, the prospect of $6/MMbtu spot prices looks remote, in the short term, so gas should be very competitive. However, in many Asian markets, including the emerging ones discussed in this paper, prices are linked to oil and are much higher than the spot LNG prices. The whole topic of gas prices in Asia, especially in relation to competition against coal, remains a key issue and is probably worthy of a paper on its own.

[198] Stern.J, Challenges to the Future of Gas: unburnable or unaffordable? NG125. Oxford Institute for Energy Studies