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The dilemma of gas importing and exporting countries

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Preface

At a time of low prices and an apparent surplus of supply in the global gas market it is important to try and identify new sources of demand, especially for LNG. In this respect, one interesting theme is how some countries are switching from their traditional role as LNG exporters to becoming importers of gas as their indigenous demand grows. Ieda Gomes explores this concept using the case studies of Malaysia and Indonesia, and she attempts to identify the key drivers behind the shifts in the gas economies of both countries.

Significantly, though, there are a few countries where gas has an existing role in the domestic energy economy, and which have historically imported gas, which have now found new gas resources and are starting to export. A prime example of this is Argentina, where the discovery of large shale gas resources has led to a gas surplus and the opportunity to generate export revenues. This paper analyses this example as a contrast to the first two and examines whether it is a sustainable situation.

Overall, we believe that this paper can provide some important insights into the factors which can influence the position of gas in a country's energy balance, especially if the prevalence of hydrocarbons has created a dependency via subsidies prices or other politically-driven strategies. There are a number of other examples around the world (Algeria could become a prime instance) where the demands of the domestic market can undermine a country's ability to export its energy resources, and as a result we hope that this analysis can provide a greater understanding of the key drivers and consequences of this outcome.

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The responsibility for all the views expressed and all the conclusions reached is solely mine.

Introduction

Over the last 5-10 years a growing number of erstwhile natural gas exporting countries started to import either LNG or pipeline gas, or both to meet growing supply demand imbalances. Amongst these countries we can count Malaysia, Indonesia, Argentina, Egypt, Oman, the UAE, Myanmar and even the United Kingdom. In some cases, such as Argentina and Egypt, as imports ramped up there was a moratorium on exports. In others, such as Malaysia and the UAE, high value LNG exports were maintained whilst imported LNG and pipeline gas satisfied the demand in the power and industrial sectors. In Oman, there was a continuity of exports, but the LNG plants had to curtail production so that feed gas could be diverted to the domestic market. In Indonesia, besides reducing and even shutting LNG production, part of the LNG output was reserved to the growing domestic market. In the United Kingdom, the decline in production from the North Sea fields, lack of seasonal storage availability and pipeline connectivity with Europe prompted pipeline imports followed by LNG imports in 2005[1].

Such dynamics are a result of, among other factors:

- the initial availability of low cost domestic gas [2] spurring fast growth in domestic demand, followed by depletion of domestic resources;
- lack of gas transportation infrastructure connecting remote producing regions with key consuming markets, which in turn fosters either the development of local LNG receiving terminals or chokes natural gas production; and
- Governments' goals to promote industrialisation through the availability of cheap gas, resulting in falling investment in exploration and development of gas resources, as producers are not remunerated in line with cost of supply.

The availability of lower-CAPEX fast track floating regas schemes has facilitated the development of LNG receiving terminals, allowing the supply of gas to regional markets within 2-3 years from project concept to implementation. The willingness of suppliers to sell on spot and short-term LNG contracts and the support of the host government have also been instrumental in the implementation of such schemes.

This paper will look at three countries: Malaysia, Indonesia, and Argentina, where natural gas plays a leading role in the energy mix and where the government exerts heavy influence on pricing and regulation. There are two main distinctive categories of LNG/gas importing/exporting countries, as exemplified below:

1. Countries with an established gas market which resorted to imported LNG when domestic production started to fall due to fast demand growth and disincentives to domestic gas exploration resulting in gas/energy shortages, for example Argentina.

- **Argentina**: In the first half of the 2000s Argentina exported gas via eight pipelines supplying Chile, Brazil and Uruguay. Government intervention and subsidies to end-user prices led to a halt in exploration investment and accelerated growth in gas consumption. In 2005 Argentina started to curtail and finally interrupted all gas exports and in 2008 it started importing LNG. In 2016 it started to import LNG delivered to Chile's terminals and transported through the reversal of flow of the existing gas export pipelines. Argentina also increased the amount of pipeline imports from Bolivia. More recently, Argentina's fortunes have changed as domestic gas production, mostly from higher cost, incentivised unconventional resources, jumped to the point where Argentina is gradually reducing imports and has started to export to Chile again during summer months. In 2019 Argentina imported 1.7 BCM of LNG vs 3.5 Bcm in 2018 and became an LNG exporter (0.08 BCM).

[1] The UK started importing LNG in 1959 at Canvey Island but the terminal was closed in 1994. (Canvey Island, 2010)
[2] Often Associated Gas or Government entitlement to profit gas from Production Sharing Contracts

2. Countries where the LNG producing facilities are located in remote regions and the gas fields feeding these plants are not connected to regional demand markets due to technical and economic reasons. This is the case of Indonesia and Malaysia.

- **Malaysia**, currently the world's 5th largest LNG exporter, it started importing LNG in 2012, via a FSU[3] scheme located in peninsular Malaysia (Melaka LNG). In 2019 Malaysia exported 32.8 BCM and imported 3.74 BCM of LNG. The LNG export facilities are located on the island of Borneo and there is no pipeline connection between the island and Peninsular Malaysia. A second import terminal (shore based), Pengerang LNG, was commissioned in 2017 to serve the petrochemical and refinery complex being developed currently by Petronas and partners. Also in 2017 Malaysia's first floating LNG production plant (Satu) offloaded its first cargo offshore at the Kanowit field. Malaysia also imports pipeline gas from Indonesia and exports pipeline gas to Singapore. In 2019 it exported 1.5 BCM and imported 6.0 BCM of pipeline gas. There is a continuous decline in production from the gas fields around Peninsular Malaysia.
- **Indonesia**, whilst dropping to the position as 7th LNG exporter, with three liquefaction plants (Bontang, Tangguh and Donggi Senoro), it started to develop small LNG importing facilities in 2012, initially aimed to supply isolated island markets. There are now four operating LNG regas facilities in operation with a 5th under construction. In 2019 Indonesia exported 19.1 BCM of LNG and supplied 4.3 BCM of domestic LNG to its internal market whilst exporting 14.5 BCM of pipeline gas to Malaysia and Singapore[4]. The Government imposes a domestic market supply obligation (at least 25%) as a condition for the approval of the expansion or construction of LNG projects.

This paper looks at the circumstances leading to the development of gas importing projects in exporting countries; reviewed market fundamentals, pricing policy and regulation; assesses the sustainability of such import/exporting schemes; and focuses on key lessons learned.

Malaysia

Context and evolution

The economy of Malaysia is heavily dependent on hydrocarbons. The oil and gas industry is currently the second-highest export earner, accounting for 15.5% of the country exports in 2018. LNG represents nearly 5% of the Malaysia export earnings[5].

The Malaysian natural gas industry was first established in the early 60s' in the wake of significant discoveries offshore Borneo and in the shallow waters of Peninsular Malaysia. In the early days, International Oil Companies (IOC's) dominated the oil and gas sector in the country, operating under a royalty and tax fiscal regime. In the wake of the first oil price shock of 1973, the Government of Malaysia decided to create its own national oil company in order to exert control over the country's oil and gas resources. The Malaysian Petroleum Development Act of 1974 allowed for the creation of PETRONAS, which was granted the exclusive rights to explore, develop and produce petroleum resources within Malaysia and to regulate the upstream sector[6]. Petronas changed the oil & gas concession contracts into production share contract agreements, with rights granted by Petronas to private players.

Petronas commissioned a Gas Master Plan in 1981, in line with the government Import Substitution Industrial Strategy II, based upon the implementation of heavy industries and large-scale production for export, which in turn required cheap and available energy. This set the scene for the development of a comprehensive gas transportation and gas utilization infrastructure.

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[3] FSU: Floating Storage Unit
[4] (IEA, 2019)
[5] http://www.worldstopexports.com/malaysias-top-10-exports/
[6] https://malaysiangas.com/wp-content/uploads/2019/03/Natural_Gas_Industry_Review-2017.pdf

In 1983 PETRONAS Gas Berhad (PGB) was incorporated as a wholly owned subsidiary of PETRONAS with the mission to build the backbone of Malaysia's transportation system, the Peninsular Gas Utilization (PGU) project. PGB operates the midstream gas infrastructure, including processing and transporting natural gas produced in the offshore fields to the markets in Malaysia and Singapore and LNG regasification plants. The 2,613 km PGU system was completed in 1998 and delivers gas to power plants and large industrial consumers, with current capacity of 36 BCM/year.

Gas Malaysia Berhad (GMB), an affiliate of Petronas, was incorporated in 1992 and is the regulated downstream business, in charge of distribution services and gas marketing for 38,000 retail customers, including small industries, and the commercial and residential sectors.[7] Meanwhile in Malaysian Borneo, Sarawak Gas Distribution Company serves Sarawak gas consumers whereas Sabah Energy Corporation serves natural gas consumers in the state of Sabah.

PGB transports and supplies gas to customers using more than 0.05 BCM/year of gas while GMB serves customers using less than 0.05 BCM of gas (previously below 0.02 BCM/year).

LNG is produced in Sarawak, at the Bintulu complex, on the island of Borneo. Malaysia started to export LNG in 1983 (MLNG Satu, three trains), followed by MLNG Dua (three trains) in 1995, MLNG Tiga, two trains in 2003 and Petronas LNG Train 9 (PL9SB), with first LNG delivered in 2016. The Bintulu LNG complex comprises nine LNG trains, with capacity totalling 29.3 mtpa. Petronas has also commissioned a floating 1.2 mtpa liquefaction plant (PFLNG Satu), with first LNG delivered in April 2017. A second floating liquefaction plant (PFLNG Dua) is expected to start operations in 2020.

In 2013 PGB commissioned the first LNG import terminal in Malaysia (RGTSU), located in Melaka, which consists of two moored FSUs and a jetty-based LNG vaporiser (5.5 Bcm); in 2017 PGB commissioned a second import terminal, the onshore LNG import facility in Pengerang, Johor (RGTP), with 5.1 Bcm capacity.[8] The second terminal aims to supply the Pengerang Integrated Complex, consisting of petrochemical plants, a 300,000 bbl/day refinery and a 1,220 MW power plant.

Figure 1 depicts key parts of the gas and LNG infrastructure in Peninsular Malaysia and Borneo (Sarawak and Sabah states).[9]

[7] https://www.gasmalaysia.com/images/download/corporate-presentation/Analyst%20Briefing_%2025March2016.pdf
[8] https://www.petronasgas.com/OurBusiness/Pages/Regasification.aspx
[9] Not to scale

Figure 1: Malaysia natural gas and LNG infrastructure

Source: Adapted by the Author from (Petronas Gas Berhad (PGB), 2019) and (Saim, 2019)[10]

Natural gas plays an important role in Malaysia's energy mix, accounting for 35.8% of the primary energy supply in 2018.[11] Successive government plans have been put in place, aiming at diversifying Malaysia's energy mix by increasing the share of natural gas, which was only 16% in 1990.

As of December 2018, Malaysia stood as the second largest producer and consumer of natural gas in Southeast Asia. In 2019 it dropped from 3rd to 5th largest LNG exporter in the world (34.8 BCM), after Qatar, Australia, USA and Russia.[12]

Malaysia has two distinctive gas consuming/producing regions with the following features:

- Borneo (states of Sarawak and Sabah)
  - The key gas consuming facility is the LNG liquefaction complex in Bintulu (Sarawak), supplied with gas produced from offshore Sarawak and Sabah's gas fields. A 512 km pipeline transports gas from Sabah to Bintulu.
  - Power and non-power consumers in Sarawak and Sabah
- Peninsular Malaysia
  - Gas supplies from
    - Peninsular Malaysia offshore fields
    - Imported gas from Indonesia offshore, Natuna Block B
    - Offshore gas from the Malaysia-Thailand Joint Development Area (JDA) and Malaysia-Vietnam PM3 Commercial Arrangement Area (CAA)

[10] Map not on scale
[11] (BP plc, 2019)
[12] (BP plc, 2019), (International Gas Union, 2020)

- Imported LNG through two terminals in Melaka and Johor – in 2018 Malaysia imported 1.69 Bcma from Australia and Brunei

- Key gas consumers: power, petrochemicals, refinery, and other industries
- Gas exports by pipeline to Singapore

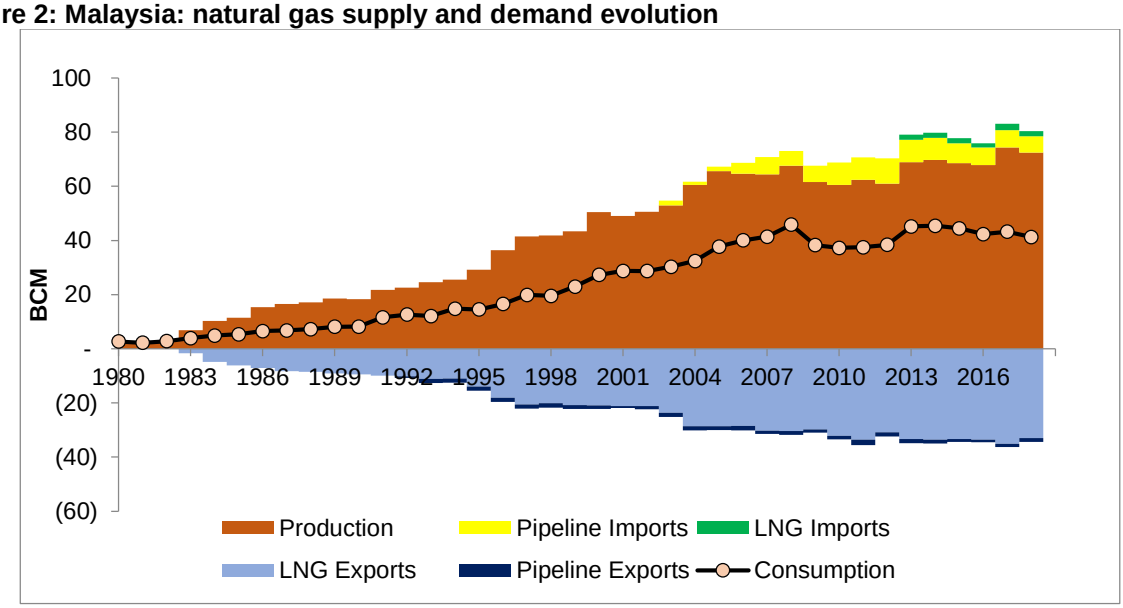
The dynamics of natural gas exports and imports

Malaysia displays distinctive features when compared to other emerging gas markets, because it has a large, albeit declining, domestic gas production and, at the same time, the country exports and imports pipeline gas and imports and exports LNG. In addition, Petronas has developed a large and comprehensive international oil and gas business, with investments in the Americas, Europe, Australia, Africa and the Middle East.

The evolving dynamics of gas exports and imports in Malaysia can be explained by the following factors:

- Government encouragement for the use of natural gas to underpin Malaysia's industrialisation.
- Geographical disconnection between gas production regions in the island of Borneo (Sarawak and Sabah) and gas consuming regions in Peninsular Malaysia. The latter have been historically supplied by neighbouring maturing fields whereas Borneo's production was channelled to LNG export projects, underpinned by long term SPAs.
- Decades-long gas price control by the government, fostering demand and inefficient use of energy, burdening Petronas investment capacity and discouraging the development of more expensive domestic production.
- Ageing and depleting gas fields in Peninsular Malaysia, without price support to develop more expensive marginal and deeper prospects, leading to the implementation of LNG import terminals.

Figure 2: Malaysia: natural gas supply and demand evolution



Source: (IEA, 2019)

Malaysia's export/import dynamics can be characterized by four phases (see also Figure 2) above.

1. 1983-1996: Balanced supply/demand in Peninsular Malaysia and start of exports from Bintulu (Sarawak province)

This period was characterized by a steady production growth, which allowed meeting a growing domestic demand as well as the start of pipeline exports to Singapore (1992) and LNG from Bintulu (1983).

The then modest country demand was concentrated in Peninsular Malaysia, which was supplied by eastern Malaysia offshore gas fields, mostly associated and in shallow water, whereas Sarawak offshore fields supplied the LNG plants and the local market. Due to the distance from Sarawak to Peninsular Malaysia it was not economical to build pipelines linking the two regions.

During the period 1983-1992 domestic demand grew 13.82%/year on average as a result of the government's goal to diversify the Malaysian economy from commodity-exporter into an export-orientated manufacturing Asian Tiger. Such ambition was enabled by the construction of the countrywide transmission pipeline (the Pipeline Gas Utilization - PGU) and by the availability of low cost shallow water gas. In addition there was a small surplus: in 1992 Malaysia started pipeline exports to Singapore and, in 1995, Petronas commissioned new trains for MLNG. It was a period of accelerated economic growth with GDP expansion peaking at 10% in 1996.

2. 1997-2002: The Asian crisis of 1997-1998 and government intervention on gas prices

The economic crisis in Asia resulted in slower growth of domestic consumption (1999-2002), and short-term stagnation in LNG exports and domestic production.

Until 1997, gas prices to domestic consumers were based on cost of supply plus a margin for Petronas, and linked to international prices of oil products (Marine Fuel Oil). With the sharp devaluation of the domestic currency, the government intervened, and implemented a policy of controlled gas prices denominated in Ringgit, mostly below cost of supply. The new policy was, initially applied to power consumers (1997) and afterwards to industrial consumers (2002). The fixed price policy was aimed to last for 3 years but remained in place for more than 20 years.[13]

The Malaysian Government's decision to regulate gas prices for the power sector in Peninsular Malaysia and Borneo resulted in electricity tariffs amongst the lowest in Southeast Asia[14]. Demand for natural gas in the power sector grew and reached a peak in 2000 when it accounted for 74[15] percent of the electricity generation mix for the country.

3. 2002-2012: demand growth in Peninsular Malaysia and exports to Singapore met by imports from Indonesia and new production from the Joint Development/Commercial Areas with Thailand and Vietnam

After the end of the 1997-1998 crisis, the economy started to grow again. In the period 2002-2007 domestic gas demand increased on average by 8.37% per annum, led by growth in manufactured goods exports, particularly electronics and electrical products, and massive government spend, which fostered power, industry and integrated petrochemical projects. Those energy intensive projects also benefited from heavily regulated gas prices.

Domestic gas fields around Peninsular Malaysia entered on rapid decline due to accelerated extraction rates, which in turn led to frequent supply interruptions.

In order to meet continued demand growth, Malaysia started importing pipeline gas from Indonesia in 2003 (Block B – West Natuna field). Thereafter, the country started to bring gas from the offshore Malaysia-Vietnam PM3 CAA in 2003, and from 2005 onwards from the Malaysia-Thailand JDA[16].

[13] (Kumar, 2020)
[14] (Zainuddin, 2017)
[15] (Malaysia Energy Commission , 2018)
[16] Not accounted as importation, because the production is split between Malaysia, Thailand and Vietnam

In addition to export obligations to LNG customers, Malaysia continued to serve pipeline export contracts with Singapore's, Keppel Gas (1.2 BCM/year) and Senoko Energy (0.41 BCM/year) with expiry dates between 2022 and 2031.[17]

According to industry sources, in 2011 37% of Peninsular Malaysia demand was met by imports from Indonesia and the shared areas with Thailand and Vietnam[18]. Domestic production and pipeline imports from Indonesia were not enough to meet export obligations and to also supply the domestic market in Peninsular Malaysia. The successive gas outages from 2004 to 2011, due to operational problems, ageing facilities and declining production caused a national outcry.

In addition, the increasing subsidy burden due to the government intervention on prices weighed down on Petronas' finances and discouraged investment in more expensive exploration areas.

In order to assure security of supply and reduce the subsidies burden the Government undertook the following actions:

- Enact a gas price reform in 2010 (the Subsidy Rationalisation Programme), aiming to gradually increase regulated prices by RM 3.0/MMBtu every six months until they reached LNG export parity. However, the government only allowed for one price increment in June 2011 and froze further increases ahead of the 2013 national elections.
- Deployment of new tax and investment incentives as well as risk sharing contracts, starting in 2010, for exploration and development of deepwater and marginal fields.
- PGB started to develop a floating LNG import terminal in Melaka.

4. 2013-present: start of LNG imports, price and market reforms

The Melaka RGTSU terminal started commercial operations in 2013. In order to meet domestic demand and export commitments, Petronas signed a 2mtpa, 20-year LNG import agreement with Australia's Gladstone LNG (GLNG), starting in 2014, with an option for an additional 1mtpa. Petronas holds a 40% stake in GLNG. Singapore has lean gas grid specifications; therefore, the import of lean LNG from GLNG also supports meeting Singapore quality requirements. In 2019 Malaysia exported a total of 1.50 BCM/year to Singapore[19].

A second LNG import terminal was commissioned in Johor, east Malaysia in 2017 to supply a large integrated petrochemical, refinery and power complex (RAPID).

The Subsidy Rationalisation Programme resumed in 2014 but price increases were watered down to RM 1.5/MMBtu every six months; the increases were implemented until December 2019.

The price reform contributed to stabilise domestic demand, however LNG imports continued to grow, due to lower domestic production in Peninsular Malaysia and a decrease in pipeline imports from Indonesia, which had its own production problems. In 2019 LNG imports reached 3.59 BCM.[20]

In order to create a more competitive gas market, attract new investment in exploration and production and diversify supplies the government decided to push for further regulatory reform. The Gas Supply (Amendment) Act 2016 establishes the conditions for the implementation of Third-Party Access (TPA) for pipelines and LNG terminals.

In addition, in 2017 the government started to roll over an Incentive Based Regulation (IBR) framework which sets the base tariff for a regulatory period of three years starting in January 2017 and allowing changes in the gas costs to be passed through to the end users every 6 months via a Gas Cost Pass-

[17] https://www.businesstimes.com.sg/top-stories/gas-swap-sees-spore-bound-png-re-routed-to-indonesia
[18] https://www.thestar.com.my/business/business-news/2011/11/01/letter-to-the-pm-on-gas-shortage
[19] IEA Gas Database
[20] (International Gas Union, 2020)

Through (GCPT) mechanism. The Act came into force in January 2017 and it has been implemented by the Energy Commission.

Natural gas prices: subsidies and reforms

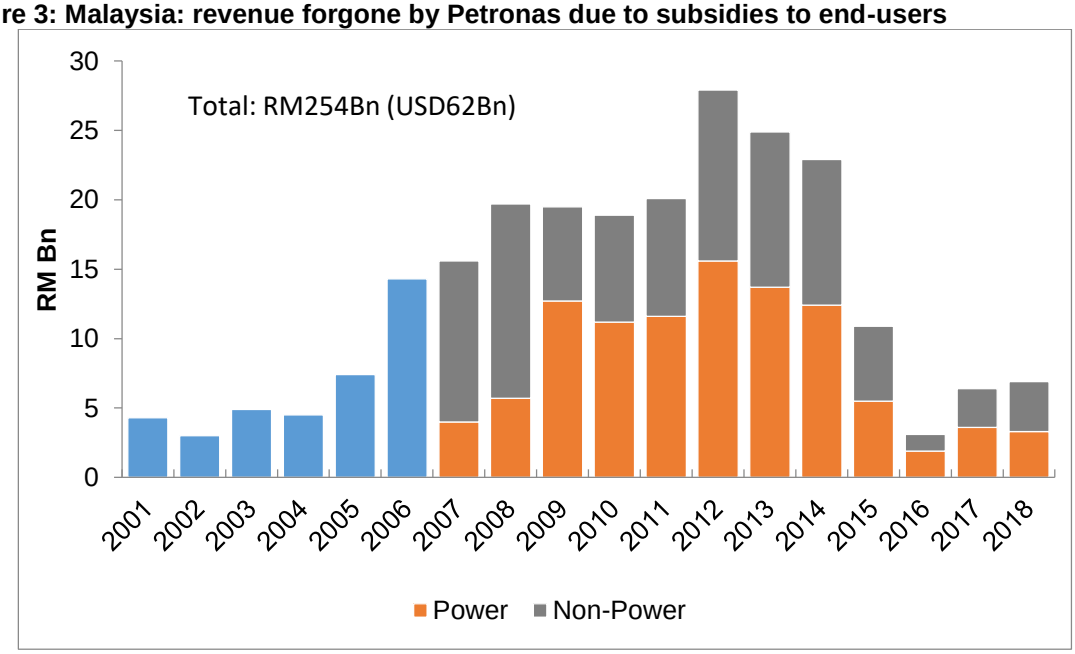
Malaysia has historically focused on maintaining a steady hydrocarbons reserves base, in order to meet its supply commitments internally and abroad and, at the same time providing affordable gas supplies to the domestic market.

Before the 1997 Asian crisis, gas prices for power plants and industrial customers were set in equivalence to Marine Fuel Oil (MFO) international prices and would remunerate Petronas cost of supply. After the intervention of the government, domestic gas prices were frozen below well-head prices and LNG import parity prices. [21]

From 2003 onwards the growth in domestic demand coupled with increased subsidies in gas and electricity prices resulted in substantial deficits for the government and Petronas.

The so-called "forgone revenue" accumulated by Petronas reached RM254.7 billion (USD 62bn) in the period 1997-2018 (Figure 3). In FY2018 alone, the revenue forgone in respect of the regulated pricing mechanism imposed on the supply of gas to Peninsular Malaysia reached RM6.9bn (USD 1.69bn) of which RM 3.3 bn for power (USD 0.81bn) and RM3.6bn (USD 0.88bn) for the non-power sector. The revenue forgone is the difference between domestic end-user prices and Petronas LNG FOB price and/or the cost of the opportunity lost to sell domestic gas at the equivalent export price.[22] [23]. The gradual implementation of the Subsidy Rationalization Programme (SRP), further detailed in this section, effectively contributed to reduce Petronas' losses through subsidies.

Figure 3: Malaysia: revenue forgone by Petronas due to subsidies to end-users



Source: (Petronas Gas Berhad (PGB), 2019)

A rough estimate of the subsidies for the power sector is shown in Table 1 below, which compares the opportunity price for Petronas when the SRP started to roll again in 2014 with 2017. Due to lack of data for gas consumption and forgone revenue in 2019, it was not possible to provide a more updated figure. The calculated impact of the prices charged to industrial consumers would be similar to the power sector

[21] (The Lantau Group, 2014)
[22] https://www.petronas.com/ws/sites/default/files/downloads/PETRONAS%20Annual%20Report%202018.pdf
[23] https://www.iisd.org/gsi/sites/default/files/ffs_malaysia_czguide.pdf

in 2014 but slightly better afterwards because gas prices for industries received a smaller discount (10%) when compared to 15% for power consumers.

Table 1: Impact of forgone revenue and implied opportunity gas price for Petronas

	2014	2017
Regulated gas price power (USD/MMBtu)	4.64	5.10
Forgone revenue power sector USD billion	3.79	0.837
Gas consumption power (Bcf)	589	486
Forgone price (USD/MMBtu)	6.43	1.72
Implied opportunity price Petronas (USD/MMBtu)	11.07	6.82

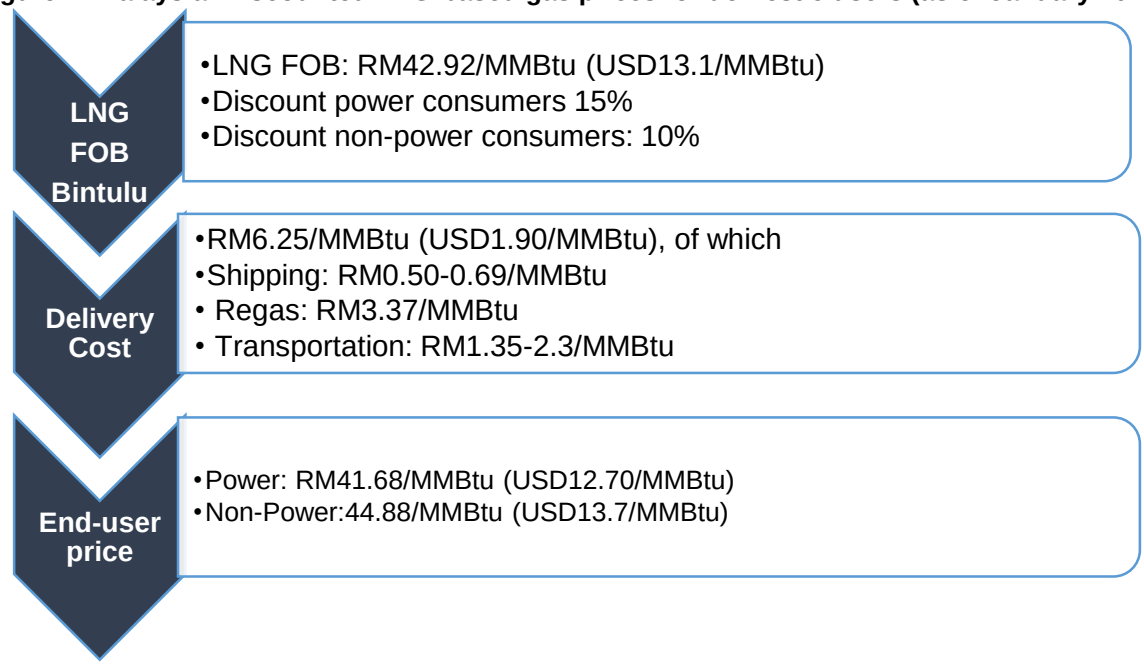
Source: Author, adapted from Petronas and IEA data

The SRP determined that the gas price should increase by MYR 3/MMBtu every 6 months, starting in 2011, to allow for a gradual alignment of domestic regulated gas prices with Malaysia's LNG FOB prices. The initial objective was to achieve market parity prices by 2016.

Initially there was little traction for the programme, as LNG prices were quite high in 2011 and there was political pressure to postpone the price hike until the national elections of 2013. Effective 1st January 2014, a restructured SRP established two categories of consumers and respective gas prices[24]:

- Tier 1, regulated prices: for consumers with pre-existing contracts. Prices would be increased by RM1.5/MMBtu every 6 months[25], until reaching parity with Tier 2 consumers;
- Tier 2, market-based, LNG-indexed prices: for new consumers and additional volumes sold to consumers with pre-existing contracts. Prices would follow LNG WAP[26] parity ex-Bintulu plus delivery costs, minus a discount of 10-15% for large off-takers.

Figure 4: Malaysia: Discounted LNG-based gas prices for domestic users (as of January 2014)



Source: Adapted from (Energy Commission, 2014)

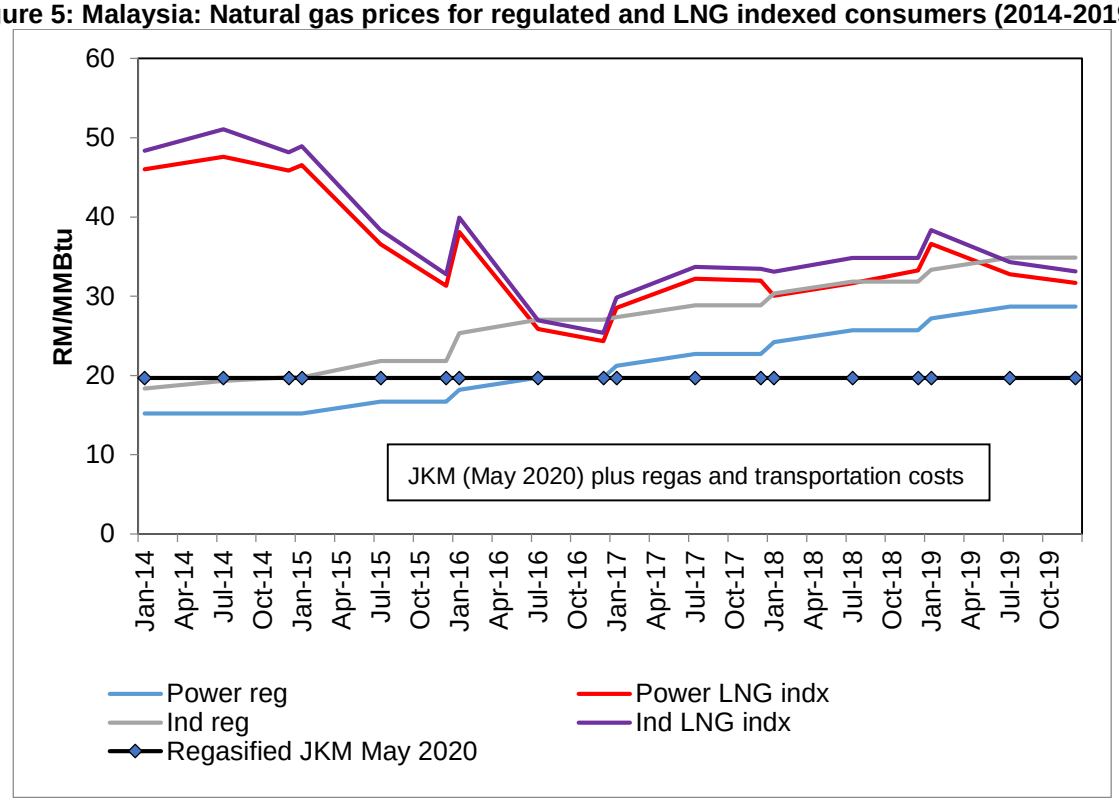
[24] (Malaysia Energy Commission, 2014)
[25] The original objective was to increase prices by RM3 /MMBtu every 6 months
[26] WAP is the weighted average price of LNG at Bintulu, published by the Department of Statistics of Malaysia

Since then LNG prices have gone down considerably. For example, in December 2019 the average FOB ex-Bintulu price was around USD 7.50/MMBtu; as a consequence Tier 2 end-user LNG-indexed prices were USD 7.80/MMBtu and USD 8.16/MMBtu, respectively for power and non-power consumers. The regulated prices were at USD 7.07 for power and 8.58/MMBtu for non-power consumers.

In the period 2014-2019 regulated gas prices increased by nearly 90 % for power consumers and now-power consumers in local currency.

Figure 5 depicts the evolution of prices charged to power and large industrial consumers outside the GMB concession franchise. As of December 2019, the Tier 1 regulated price for industrial consumers was 5% above the Tier 2 LNG-indexed prices for the same category. Regulated prices for power consumers were 10% lower than the LNG indexed prices.

Figure 5: Malaysia: Natural gas prices for regulated and LNG indexed consumers (2014-2019)



Source: Author estimate and https://www.st.gov.my/

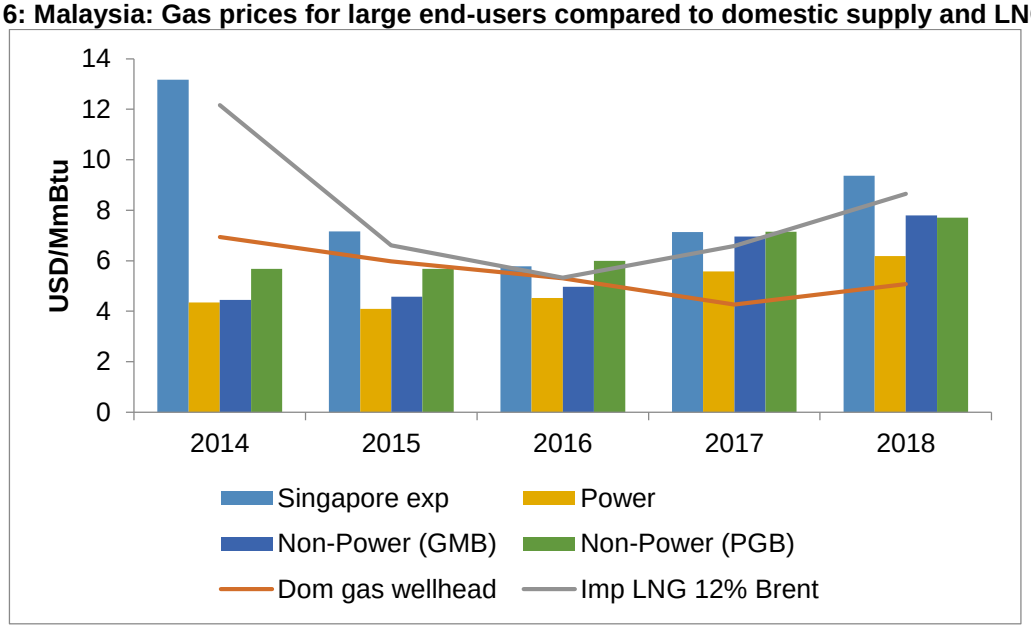
Considering JKM forward prices of USD 2.0 – 4.24/MMBtu (Jun-Dec 2020)[27], large energy consumers could benefit from accessing regulated pipelines and LNG terminals to import spot LNG into Malaysia, resulting in regasified LNG prices below regulated gas prices as shown on Figure 5.

When translated into US dollars the domestic price increases do not seem so evident, due to currency fluctuations (Figure 6). In 2018 end-user prices were above wellhead prices (USD5.01/MMBtu). However, if Malaysia continues to increase LNG imports on long term oil indexed contracts - for example at 12%Brent - domestic end user regulated prices would be significantly below LNG import parity prices as shown on Figure 6.[28] This would deter further LNG imports by third parties on medium/long term oil indexed prices.

[27] https://www.cmegroup.com/trading/energy/natural-gas/lng-japan-korea-marker-platts-swap.html

[28] Note: domestic upstream prices refer to JDA/Peninsular Malaysia prices published by Hess in their Annual Reports: https://investors.hess.com/static-files/f0375fc7-bcbb-4b34-a984-c17c26cde53a

Figure 6: Malaysia: Gas prices for large end-users compared to domestic supply and LNG



Source: Author adapted from Energy Commission and Hess data

In parallel with the new price policy, the Government of Malaysia has also decided to open the midstream infrastructure to third party access (TPA), which came into force in January 2017. This includes access to the two LNG regasification facilities. According to the Malaysian Gas Association, seven import licenses have been issued by the Energy Commission as of 1Q2020.

In October 2019 Shell Malaysia Trading (SMTSB) delivered the first TPA cargo at the Melaka terminal to supply two power plants owned by TNB in Port Dickson and Klang. SMTSB signed a Gas Transportation Agreement with PGB and a Terminal Usage Agreement with Regas Terminal (Sg. Udang), a subsidiary of PGB[29].

The outlook for supply and demand

As discussed in previous sections, Malaysian domestic production has not been sufficient to meet LNG and pipeline exports plus domestic demand. One could ask why Petronas does not divert LNG from Bintulu to supply the Malaysia market via the Melaka and Johor LNG import terminals?

This might not be possible due to long term pipeline and LNG supply agreements currently in place. The supply agreement with Singapore expires in 2023, whereas Malaysia LNG's long and medium term SPAs with a string of Asian buyers expire between 2021 and 2031[30]. Petronas has also medium and long term SPAs in place with Asian buyers with volumes in excess of 5 BCM/year. The contracts are denominated in USD and mostly oil-indexed.

In the absence of significant domestic discoveries, future growth in power consumption will be increasingly met by coal and possibly by renewable energy. In the period 2014-2019 coal consumption for power increased on average by 5% and for the country overall by 7.1% per annum.[31]

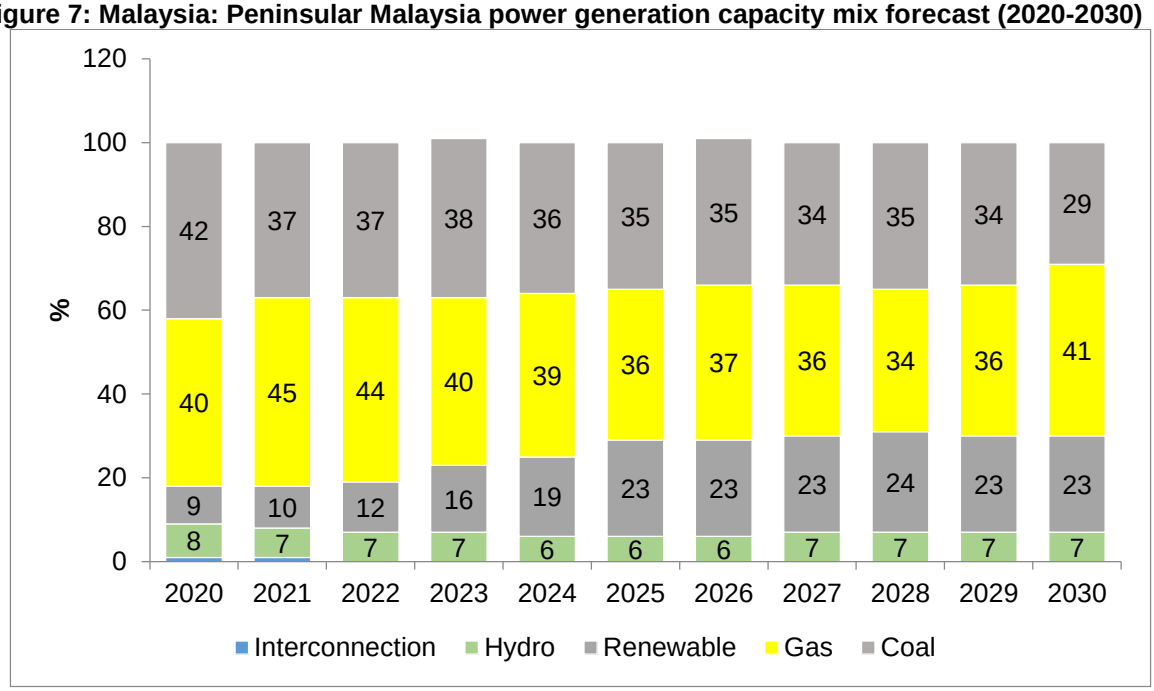
[29] https://www.thestar.com.my/business/business-news/2019/10/03/tnb-in-deal-with-shell-to-buy-cheaper-gas
[30] (GIIGNL, 2020)
[31] (BP , 2020)

Although coal represented 31% of the 33.7GW installed capacity in 2018 vs 43.6% of gas, coal already accounted for 42% of the generation output, compared to gas at 16.5% in 2017 due to lower coal prices and decreased gas availability. [32],[33]

According to Malaysia Energy Commission projections, coal-fired capacity is expected to rise to 42% in 2020, then decline to 35% and 29% by 2025 and 2030, respectively (Figure 7). But coal might still account for 55% of the generation output, up from 43% in 2016. As of March 2020, TNB commissioned a brand new 2,000 MW coal-fired power plant employing ultra-supercritical (USC) technology.[34]

At the 21st Conference of Parties (COP21) in 2015, Malaysia pledged to reduce its carbon emission intensity per Gross Domestic Product (GDP) by 35% in 2030 relative to the 2005 level, or 45% with support from developed countries. In order to achieve this goal, the Government foresees a mix of 20% of renewable energy installed capacity by 2025 (6,000 MW), meaning an added RE capacity of 3,750 MW.

Figure 7: Malaysia: Peninsular Malaysia power generation capacity mix forecast (2020-2030)



Source: (Malaysia Energy Commission, 2020)

With the addition of distributed renewable energy, peak demand from conventional power plants is expected to grow to respectively 18,431 MW in 2025 and 20,265 MW by 2030, a modest growth of 0.7% per annum.

Assuming that domestic production is maintained at a level which ensures the continuity of LNG exports from Bintulu, a decline in production from Peninsular Malaysia and the end of the pipeline imports from Indonesia in 2022, LNG imports are expected to rise significantly by 2030.

According to projections from the OIES, this would entail LNG imports of 17 BCM/year by 2030, increasing to 26.5 BCM/year by 2040. If these projections materialise, this might raise a question about whether some LNG from Bintulu should be diverted to the internal market as and when the LNG SPAs

[32] https://www.statista.com/statistics/865614/malaysia-total-electricity-generation-capacity-by-source/
[33] (Malaysia Energy Commission , 2018)
[34] https://www.tnb.com.my/assets/press_releases/20200321eng.pdf

start to expire. Regional neighbour Indonesia is already diverting growing volumes of domestically produced LNG to meet domestic demand, as explained further in this paper.

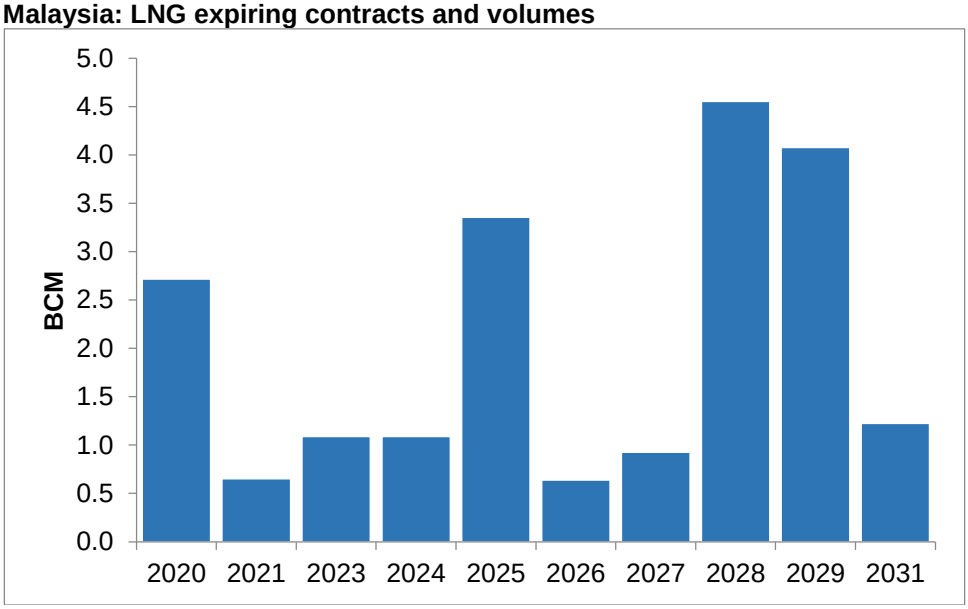
Table 2: Malaysia: Potential LNG imports forecast (2019-2040)

BCM/year	2019	2030	2040
Dom Production	67.8	64.2	62.0
Pipeline Imports	6.0	0	0
LNG Imports	3.7	17.0	26.5
Pipeline Exports	1.5	0.9	0
LNG Exports	32.8	38.7	38.7
Dom Consumption	41.3	41.6	49.8

Source: Adapted from (Fulwood, Gas in South Asia, OIES Internal Seminar, 2020)

By 2030 there are 19.1 BCM of LNG export contracts expiring, growing to 20.3 BCM by 2031 as shown in Figure 8 below, whereas the OIES predicts imports of 17 BCM by 2030. This might create political pressure to divert some of the uncontracted LNG into the domestic market, as is happening currently in Indonesia.

Figure 8: Malaysia: LNG expiring contracts and volumes



Source: Adapted from (GIIGNL, 2020)

Key insights

New domestic supplies to Peninsular Malaysia are becoming more expensive, requiring gas prices above USD 5/MMBtu as demonstrated by the prices agreed with Hess Carigali. The continuity of market orientated prices reforms is essential to allow for Petronas to ramp-up investment in domestic production.

The implementation of the price revision mechanism has suffered hiccups and amendments but progressed well from 2014 onwards. Under the current LNG international prices, regulated and LNG indexed prices are fairly well aligned, albeit still below full LNG export parity prices. If LNG export parity prices continue going down, as a result of decreasing oil prices, domestic gas prices based on LNG FOB might be too low to encourage domestic gas development on marginal and deep-water fields.

Taking into account the softness of LNG international prices, there have been discussions on whether Malaysia should adopt a weighted average cost of supply, including marginal domestic production – for

the calculation of price pass-through to Tier 2 customers. This might open some space for the development of more expensive gas fields.

Long and mid-term contract obligations with LNG and Singapore buyers and competitive pressure require that Petronas should prioritize exports rather than divert volumes to the domestic market. In the past supply cuts to Singapore dented Malaysia and Indonesia reliability as international gas exporters.

Going forward one should expect a decrease in gas to power consumption until 2030 due to the increasing role of coal and renewable energy. Post 2023, gas demand in Peninsular Malaysia will be boosted by the commissioning of the RAPID industrial complex in Johor with most of the demand met by imported LNG. Demand growth in Sabah and Sarawak looks stronger compared with that of Peninsular Malaysia. In Sabah, new energy-intensive industrial projects in Kimanis and Sipitang (such as SAMUR – Ammonia Urea Complex) are being developed, with several others in the pipeline. In Sarawak, gas demand growth will be driven more by the power generation sector.

Despite the stated objective of enhancing competition, progress in the implementation of the TPA policy has been slow. As of early 2020 there have been no other LNG deliveries from third parties, possibly due to softer power demand and the increase in coal generation, aggravated by the impacts of COVD19.

It is worthy of note that although significantly closing the gap, LNG indexed prices are not fully LNG export parity prices, because industrial and power consumers receive discounts of 10% and 15% respectively vis-à-vis Malaysia LNG WAP. This would disadvantage 3rd party sellers competing with Petronas for medium/long term oil indexed contracts.

The LNG plants in Bintulu require feed gas in excess of 40 Bcm at peak; however domestic gas production is expected to drop continuously until 2040. If demand is not curbed and domestic production is not sufficiently ramped up, by 2040 Malaysia could become a net gas importer. By 2030, imported LNG volumes could exceed the Melaka and Johor LNG terminal capacity, raising the need for capacity expansion or even a third terminal.

As LNG export contracts expire in the next decade, Malaysia could divert erstwhile export volumes into the domestic market, ending up a 5-decade tradition of gas exports.

Indonesia

Context and evolution

The oil industry in Indonesia dates from the 19th century, with first oil discovered in north Sumatra in 1885. The gas industry started operations in 1863, with the introduction of town gas, manufactured from coal, to light the streets of Jakarta. Indonesia was one of the first producers of LNG, with the first project commissioned in 1977. It maintained the position of top world producer until 2005[35].

PT Pertamina (Persero[36]), the national oil company, was created in 1968 but it is not the only upstream producer, co-existing with several international and domestic companies. PT Perusahaan Gas Negara (PGN) operates the gas transmission and distribution grid. In 2018 the government combined the two companies under the umbrella of a holding enterprise. The government-owned corporation PT Perusahaan Listrik Negara (PLN) is responsible for the majority of Indonesia's power generation with exclusive powers over the transmission, distribution and supply of electricity.

SKK MIGAS manages upstream oil and gas activities through Joint Cooperation Contracts, under the umbrella of the Ministry of Energy and Mineral Resources (MEMR), replacing the previous regulator BP MIGAS. BPH MIGAS is the downstream regulator for oil and gas and retail fuel distribution and supply.

[35] https://www.igu.org/sites/default/files/node-document-field_file/igu-oct2019_layout_lo-res-web.pdf
[36] Persero is a state-owned limited liability company

Indonesia was an early adopter of Production Sharing Contracts which were signed by Pertamina and international oil companies. The discovery of the Arun field, by Pertamina in association with Mobil Oil and the Badak field, in association with Huffington, prompted the development of LNG projects, respectively Badak LNG (Bontang LNG) [37] (1977) and Arun LNG (1978). The discovery of additional gas fields and the diversion of associated gas to the LNG plants led to successive debottlenecking and capacity expansion allowing Arun LNG to reach nameplate capacity of 12.5 mtpa, whereas Bontang reached 22.5 mtpa. In 2009 the 7.6 mtpa BP-led Tangguh LNG (West Papua) started operations and the Donggi Senoro 2.5 mtpa project in Sulawesi delivered its first cargo in 2015. Tangguh LNG is building a third train expected to start-up in late 2021.

Two other LNG projects are currently under development: INPEX's Abadi LNG (Masela block, Timor Sea), slated for 9.5 mtpa and start-up by 2024/2025 and the much delayed 2 mtpa EWC-led Sengkang LNG (South Sulawesi), consisting of 4 modular trains of 0.5 mtpa each.

According to BP, Indonesia's gas reserves amounted to 97.5 Tcf in 2018[38]. The country is the 12th largest gas producer in the world, and together with the USA it ranks as the 5th largest LNG exporter. Approximately 53% of Indonesia's gas production is consumed in the internal market; the balance is exported as LNG and pipeline gas to Malaysia and Singapore. Domestic production has decreased from a peak of 85.7 Bcm in 2010 to 67.1 Bcm in 2019[39] as a consequence of maturing gas fields.

In spite of uncertainties introduced by changes in the fiscal regime, Indonesia has seen some positive developments on the domestic production front. In 2016 BP and its partners announced the decision to invest in Tangguh LNG train 3 (3.8 mtpa.[40] In 2017 the ENI-led offshore Jangkrik Development Project, in East Kalimantan, provided additional gas supplies into Bontang LNG. In early 2019 Repsol and its partners announced a large gas discovery in the Sakakemang block in South Sumatra, with a preliminary estimate of 2 Tcf of recoverable resources[41] which should supply the domestic market. Pertamina's Jambaran Tiung Biru project in eastern Java is slated to start supplies in 2021, to power plants.

SKK Migas is also expecting that Chevron's Indonesia Deepwater Development (IDD) project will start operations in 2024 despite Chevron's recent announcements on investment cuts and reductions in gas production.[42],[43]

Despite the geographic obstacle of being a country composed of thousands of islands and the fact that demand centres are remarkably distant from production areas, Indonesia has succeeded in building 16,500 km of pipelines, three major LNG export projects, four regasification terminals and offshore pipelines connecting fields in Sumatra and the Natuna Sea to domestic markets and to Singapore and Malaysia.

The dynamics of natural gas exports and imports

Nearly 80% of Indonesia's gas demand arises from industry and power plants. The relatively incipient distribution infrastructure inhibits the development of the residential and commercial sectors, as shown in figure 9 below.

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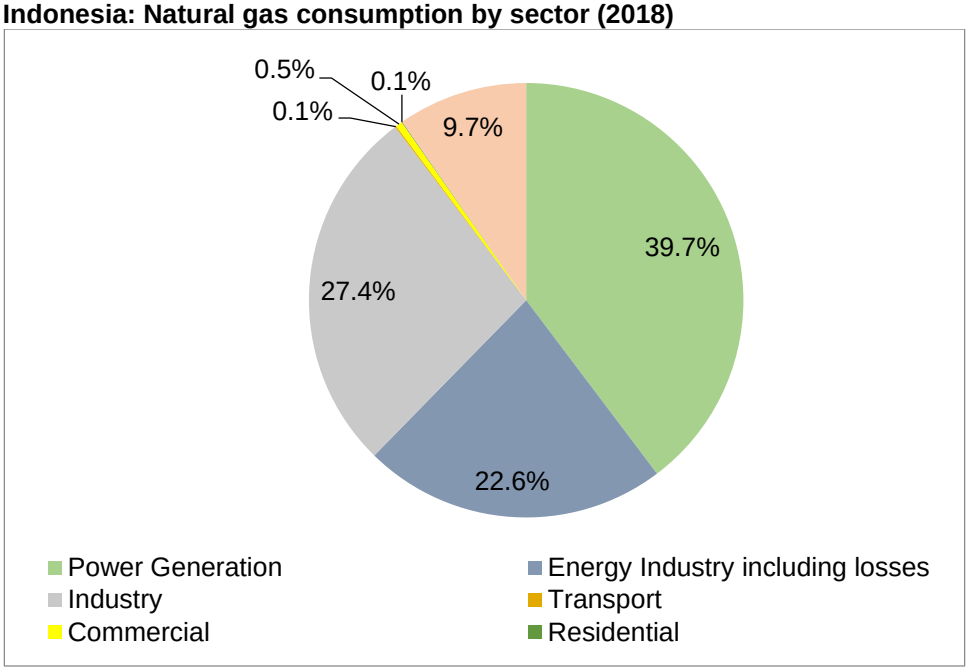
[37] (Dewanto, 2019)
[38] (BP plc, 2019)
[39] BP Statistical Review of World Energy, 2019
[40] https://uk.reuters.com/article/uk-lng-indonesia-bp/bps-tangguh-lng-plant-train-3-to-be-delayed-by-a-year-regulator-idUKKCN1UE1BV
[41] https://www.repsol.com/en/press-room/press-releases/2019/repsol-makes-largest-gas-discovery-indonesia-past-eighteen-years.cshtml
[42] https://www.reuters.com/article/us-indonesia-gas/indonesia-is-unlikely-to-begin-natural-gas-imports-in-2025-minister-idUSKCN1UQ0F7
[43] https://www.reuters.com/article/us-indonesia-chevron/chevrons-new-design-for-indonesian-gas-project-to-cut-output-regulator-idUSKCN1VQ0YX

Although the power sector accounts for a large share of gas consumption, coal is still dominant in power generation. In 2017 coal accounted for 38% of the installed capacity, versus gas at 25%; and coal accounted for 62% of the generation mix, against gas at 21%.[44]

Figure 9: Indonesia: Natural gas consumption by sector (2018)



Source: (IEA, 2019)

Until 2010, when it reached a peak production of 85 BCM/year, Indonesia was a net gas exporter with domestic production comfortably meeting the needs of the domestic market as well as pipeline exports to Malaysia and Singapore and LNG exports to Asian markets. Since then, domestic production has dropped by 18 BCM/year to 67.1 BCM/year in 2019. And although domestic demand has quintupled in the period 1985-2010, reaching 43.5 BCM, it has since then stagnated at 40-41 BCM in the last decade, due mostly to diminishing gas supplies (Figure 10 below).

The continuous decrease in domestic production has affected both the supply to the domestic market and LNG projects. Arun LNG was shut down whereas Bontang LNG's output has been severely reduced.

Gas shortages have led Indonesia to build four LNG import terminals at large gas demand regions and to impose a domestic gas obligation (DMO) whereby gas producers and LNG plants must divert at least 25% of their production or supplies to the domestic market.

Indonesia is now in a peculiar situation where it "imports" domestically produced LNG, but still exports pipeline gas and decreasing LNG volumes. But the odds are that actual LNG imports should start in a few years, coupled to the phase-out of pipeline and LNG exports.

The key factors leading to such dynamics are summarized below:

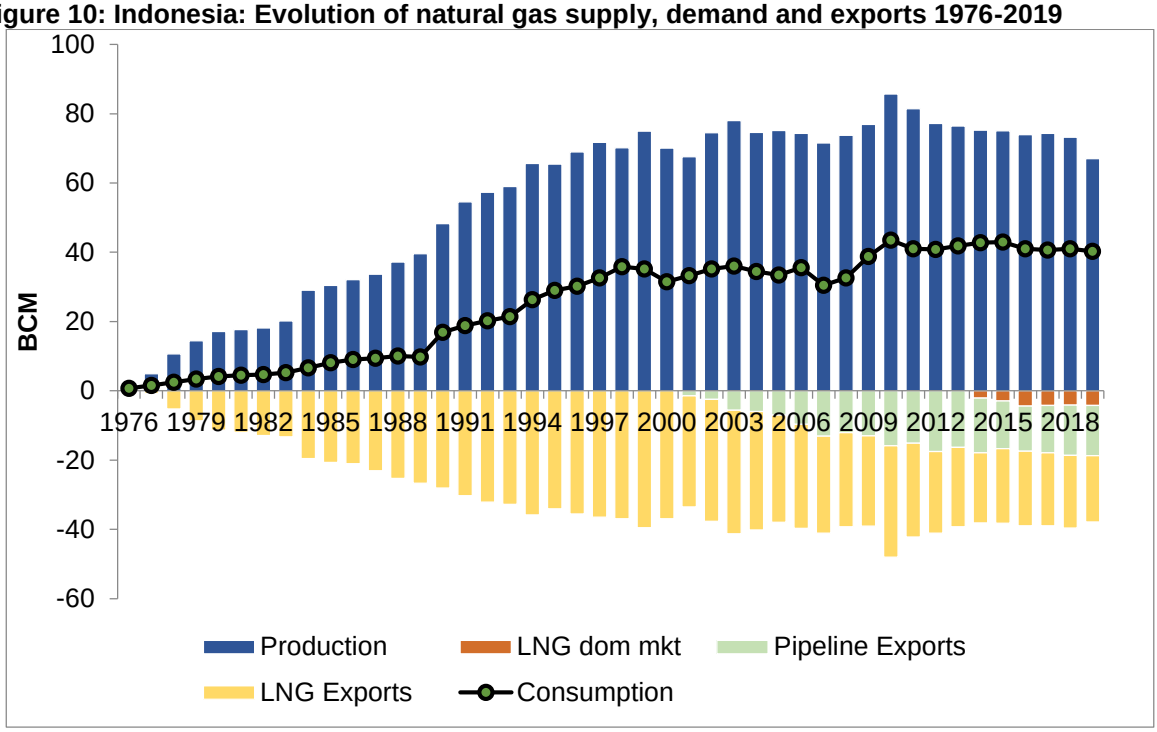
- Remoteness of the larger gas fields in the west did not allow for pipeline connections to demand centres in the east, enabling gas export schemes from those regions.
- Decreasing domestic supply, as a result of a slow-down in upstream investment; this seems to be a consequence of continuously changing regulations in the Production Sharing Contract

[44] (PwC, 2019)

(PSC) regime, including a recently introduced gross-split methodology which will replace the traditional PSC cost-recovery system, as well as Government's alleged preference to transfer operatorship to Indonesian companies. [45] [46]

- Government's decision to allocate 25% of field production to the domestic market, including LNG produced by existing projects, with growing interference on end-user prices which were once freely negotiated. A recently announced price cap of USD 6.0/MMBtu for power plants and large industrial consumers added to regulatory uncertainty.
- Availability of fast-tracking FSRU terminals allowed for the connection of the LNG plants with domestic demand centres.

Figure 10: Indonesia: Evolution of natural gas supply, demand and exports 1976-2019



Source: (IEA, 2019), (BP , 2020)

Figure 10 illustrates the historic evolution of the gas supply/demand, which can be detailed in the two phases below:

1. 1976-2010: From export-orientated to domestic market-orientated

In the 1970s, 1980s and 1990s most of Indonesia's natural gas was produced under long-term export contracts with a large share of production concentrated in remote regions in East Kalimantan and North Sumatra (Figure 11, below).

From the late 1970s Indonesia's economy benefited from higher oil prices for its exports and accelerated economic growth, due to a gradual process of urbanisation and industrialisation. After a few blips in the early 1980s caused by the collapse of oil prices, the government re-orientated the economy towards manufactured exports with the country benefiting from economic growth in other countries.

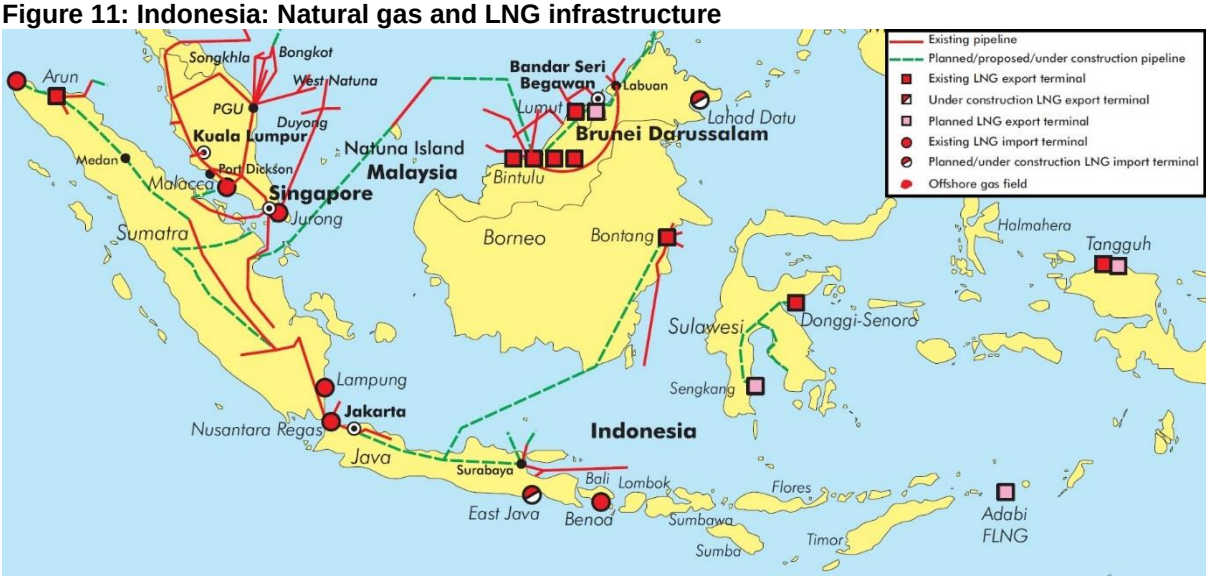
[45] https://www.pwc.com/id/en/energy-utilities-mining/assets/oil-and-gas/oil-gas-guide-2019.pdf
[46] Under this methodology, gross production of natural gas is split 52%:48% between Government and Contractor, without a cost recovery mechanism.

Domestic consumption of natural gas increased on average by 8.5% per annum in the period 1990-1999 and then by 10.4% in the period 2007-2010.

The main drivers for gas demand growth were an increased share of the industrial sector in Indonesia's GDP and urbanisation, leading to an increase in electricity consumption. Also, the country's declining oil production, due to ageing fields, led to the removal of subsidies to diesel as a fuel in 2005, causing a shift in consumption from oil products to natural gas in the industrial and power sectors. The commissioning of the 500 km South Sumatra-West Java pipeline in 2008, linking the gas producing fields of South Sumatra and the markets in West Java helped to supply the most populous region in the country.

Gas production increased in 2009-2010 due to the commissioning of the BP-led Tangguh LNG project in remote West Papua, with production from Trains 1 and 2 initially dedicated to export markets in Asia and the west coast of the USA.

Figure 11: Indonesia: Natural gas and LNG infrastructure



Source: OIES/IEA 2019

The swift increase in domestic demand for natural gas led the government in 2004 to issue a new regulation (GR 35/2004) establishing the obligation of oil and gas producers to meet a natural gas domestic market obligation (DMO). Gas producers, including LNG projects were required to assign 25% of their production to the domestic market. This was not particularly cumbersome until 2013 because the local markets around LNG plants were small, there was scarce infrastructure connecting fields to markets and the existing pipeline and LNG projects had contractual obligations with foreign buyers in hard currency.

2. 2010-present: Exports slow-down and diversions to domestic market

The depletion of ageing gas fields resulted in the gradual mothballing of Arun LNG's trains from 2000 till 2014 and the transfer of some export contracts to Bontang LNG. The Arun LNG plant ceased operations in 2014, after 36 years of LNG exports. The plant was converted into a 3 mtpa (4.1 BCM/year) LNG receiving/offloading terminal in 2015. The decline in gas feedstock availability has also impacted the output of Bontang (Badak) LNG with only four trains in operation as of the end of 2019, out of the original eight trains[47].

Gas shortages in the domestic market gradually crept up, so Indonesia started to implement a gas allocation policy in 2010. The policy was further updated by MEMR Regulation No. 6 of 2016 on

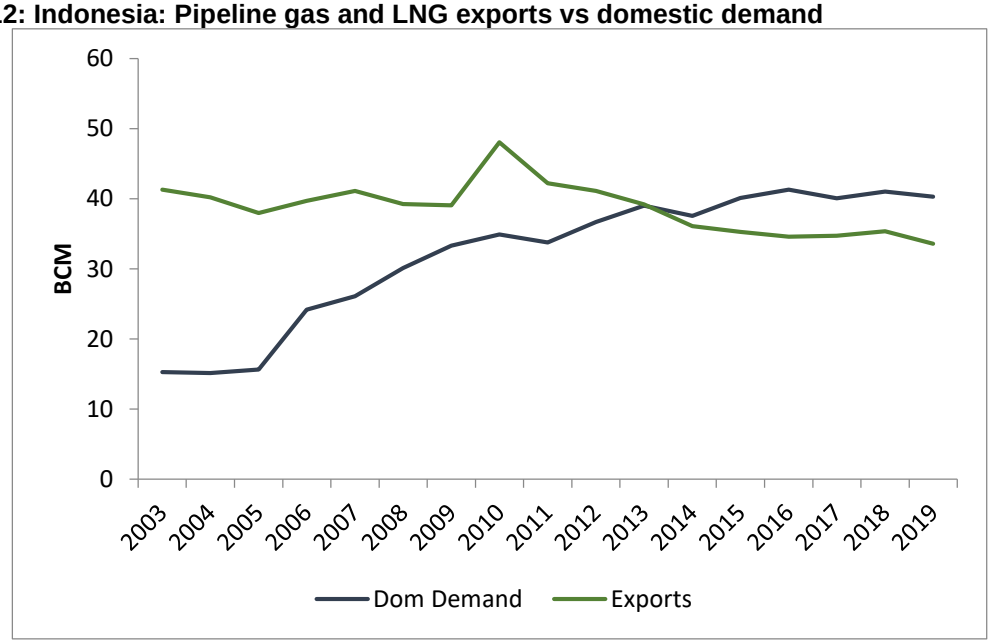
[47] (IGU, 2019)

Guidelines and Procedures for the Designation, Allocation, Utilisation and Price of Natural Gas with the following allocation priorities:

- Residential, transportation and small users
- Enhanced oil and gas production
- Natural gas as a feedstock
- Gas for power
- Gas as industrial fuel

From 2012 onwards, domestic demand continuously exceeded export volumes, which have declined from a peak of 44.8 BCM in 2010 to a low of 33.56 BCM/year in 2019[48] (Figure 12).

Figure 12: Indonesia: Pipeline gas and LNG exports vs domestic demand



Source: Adapted from (SKK Migas, 2018) and (IEA, 2019)

According to local news, the domestic market obligation for Tangguh LNG Train 3 was set at 40% of the train production whereas Donggi Senoro has a DMO of 30%[49]. Some other fields which are slated to supply Bontang LNG (ex. Chevron/DD and ENI/Jangkrik) have a DMO of 40%.

LNG supplies to domestic market

In 2015, 12% of Indonesia's LNG production was supplied to domestic terminals, rising to 18% in 2019[50]. Pertamina has already requested regulatory approval to expand Arun whilst MOL (Mitsui O.S.K. Lines) has signed agreements for the construction of a 3 BCM/year FSRU to supply the Jawa Satu LNG-fired power plant, jointly owned by Pertamina, Sojitz and Marubeni[51]. Several other LNG receiving terminals have been proposed but so far progress has been slow due to investment constraints.

[48] Exports include LNG and pipeline exports but do not include LNG consumed in the internal market (4.1BCM in 2018)
[49] https://www.offshore-energy.biz/eia-indonesias-share-of-global-lng-supply-declines-due-to-demand-growth/
[50] https://www.reuters.com/article/indonesia-gas/update-2-indonesia-plans-new-gas-pricing-for-industrial-users-in-march-minister-idUSL4N29E105
[51] https://www.sojitz.com/en/news/2018/12/20181207.php

Table 3: Indonesia: existing LNG receiving terminals

Terminal	Start-up date	Capacity (BCM/year)	Operator
Arun (Onshore) North Sumatra	2015	4.1	PT Perta Arun Gas (Pertamina and Aceh Government)
Benoa (FSU+FSRU) Bali	2016	0.4	PT Pelindo Energi Logistik (PEL)
Nusantara (FSRU) West Java	2012	4.1	Pertamina and PGN
Lampung (FSRU) South Sumatra	2014	2.5	Hoegh LNG
Total		11.1	

Source: (GIIGNL, 2019)

The average utilization of the existing terminals was circa 37% of the installed capacity as of December 2018[52], due to bottlenecks in downstream infrastructure.

In December 2013, Pertamina signed its first LNG import contract with Cheniere Energy to receive 1.52 mtpa (2.1 BCM/year) of LNG for 20 years from Corpus Christi LNG (Texas, USA). The contract was designed to start delivering 0.76 mtpa in 2018, ramping up to 1.52 mtpa in 2019[53]. However the increase in domestic gas production from the ENI-led Jangkrik Development Project has provided Bontang LNG with enough gas to produce 47 surplus cargoes thus deferring the need to import LNG[54]. Therefore domestic LNG demand – 4.3 Bcm in 2019 – has been met by allocation of LNG cargoes from Bontang and Tangguh.

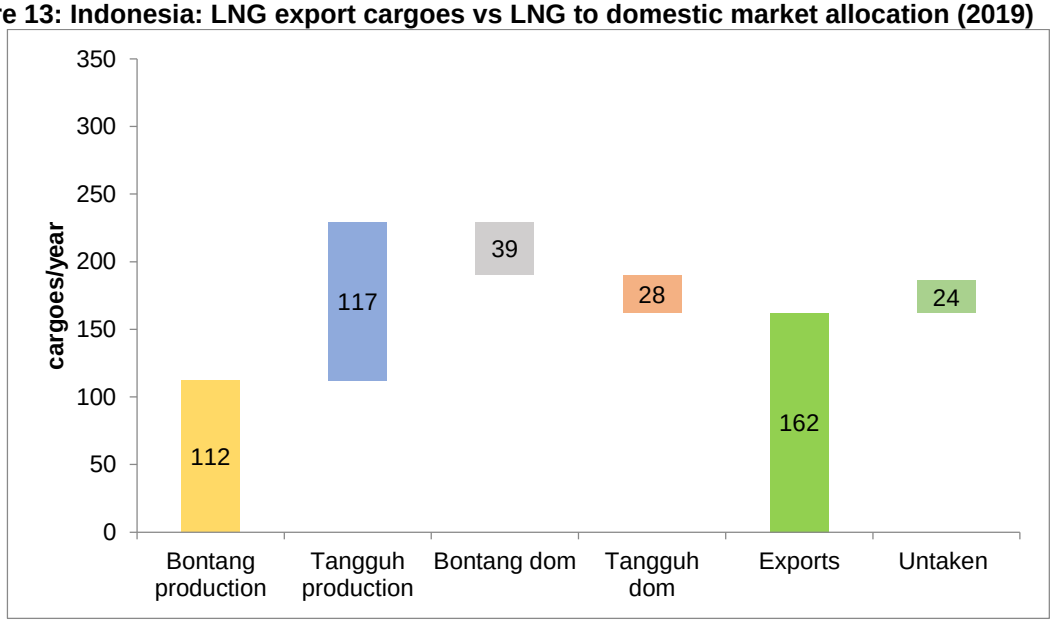
Furthermore, LNG imports are not currently supported by the incumbent Government, because importing gas is a politically sensitive issue, and conflicts with the Government stated objective of reducing imports of oil and gas, to ease the fiscal burden. PNG is also applying additional pressure to increase the rollover of the DMO for domestic LNG at regulated prices as they believe they could get cheaper supplies from domestic projects.

As a consequence, Pertamina apparently re-sold their Corpus Christi 2018-2019 cargoes to trading buyers and through spot market sales. The official discourse is that there is no need to import LNG in the short term because the domestic market can be supplied by domestically produced LNG[55].

In 2019, from a total of 229 cargoes produced at Bontang and Tangguh 67 cargoes were destined to the domestic market versus 162 cargoes for exports (Figure 13). For 2020 SKK Migas announced that the two facilities are expected to produce 212 cargoes, of which 89.6 would be from Bontang and 122.3 from Tangguh.[56] Although there were 67 cargoes allocated to the domestic market, only 40-43 cargoes have actually been taken by the Indonesian terminals, due to lower demand and infrastructure constraints. The untaken cargoes are usually sold in the spot market, although delays in obtaining approval for exports resulted in cargoes not being sold and production shut-downs reported in some areas.[57]

[52] https://www.businesstimes.com.sg/top-stories/gas-swap-sees-spore-bound-png-re-routed-to-indonesia
[53] https://www.naturalgasintel.com/articles/98882-corpus-christi-inks-second-pertamina-lng-sales-agreement
[54] https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/121917-feature-indonesia-to-postpone-lng-imports-as-domestic-output-rises
[55] https://www.reuters.com/article/us-lng-usa-sellers/lng-buyers-try-to-ditch-u-s-gas-commitments-idUSKBN1O31I5
[56] https://www.lngindustry.com/liquefaction/14012020/indonesian-lng-project-output-for-2020-revealed/
[57] https://www.thejakartapost.com/news/2015/06/08/the-real-cost-indonesia-s-commodity-export-restrictions.html

Figure 13: Indonesia: LNG export cargoes vs LNG to domestic market allocation (2019)

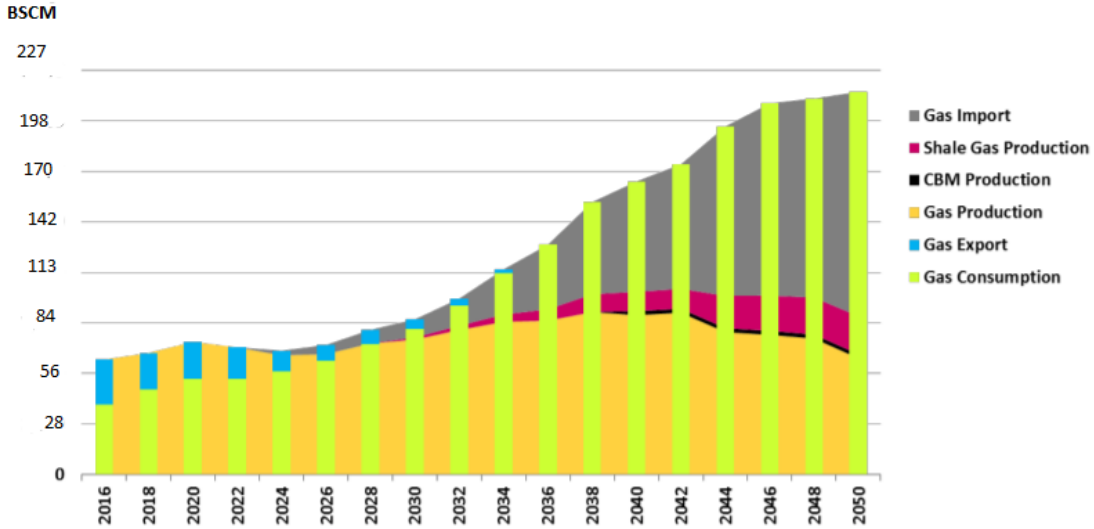


Source: Author adaptation of https://www.lngindustry.com/liquefaction/14012020/indonesian-lng-project-output-for-2020-revealed/

Gas supply and demand outlook

Indonesia gas production fell from 73.2 Bcm in 2018 to 67.1 Bcm in 2019. In April 2020 SKK Migas slashed the outlook for gas production to 59 BCM/year in 2020 due to the negative impacts of COVID19 on domestic demand. In the medium term the Government plans to increase the share of gas in the energy mix from 18.1% in 2018 to 22% in 2025, as overall energy demand is expected to grow to 248.4 Mtoe by 2025, from 185.5 Mtoe in 2018. According to SKK Migas, coal's share is expected to drop marginally from 33.2% to 30% over the same period[58].

Figure 14: Indonesia: Natural gas balance (2016-2050)



Source: (Government of Indonesia, 2018)

[58] https://www.spglobal.com/platts/en/events/americas/mexican-energy

The Government forecast shows a declining production post 2040, as fields in development by ENI, Chevron, Repsol and Pertamina are expected to sustain domestic production, with some improvement from unconventional gas resources. Gas demand is forecast to grow by 6.3% per annum from 2016 to reach circa 84 BCM/year by 2030. The Government predicts that domestic LNG demand offsets natural gas exports by 2028, when Indonesia would become a net importer and that. Indonesia would cease all gas exports by 2034 (Figure 14). The Government has already announced that "(pipeline) gas exports to Singapore will stop in 2023 and we will use the gas for the domestic market". [59] The diverted supply to Singapore will be injected into the Dumai Duri transmission pipeline to be distributed to industrial estates in Sumatra, according to the Ministry of Energy and Mineral Resources (MEMR).

The OIES projections of domestic demand are more conservative, with a growth rate in line with historic patterns, around 2.7% per annum until 2030, whereas the production forecast is in line with the Government's curve, meaning that the need for imported LNG reaches 23 BCSM by 2030. LNG exports in the OIES forecast become increasingly destined to supply the domestic market with little left for exports. The increase in LNG production post 2020 is a result of Tangguh Train 3 and Abadi LNG. In order to accommodate additional LNG demand, the existing terminals need to be expanded before 2030.

Table 4: Indonesia natural gas supply/demand forecast

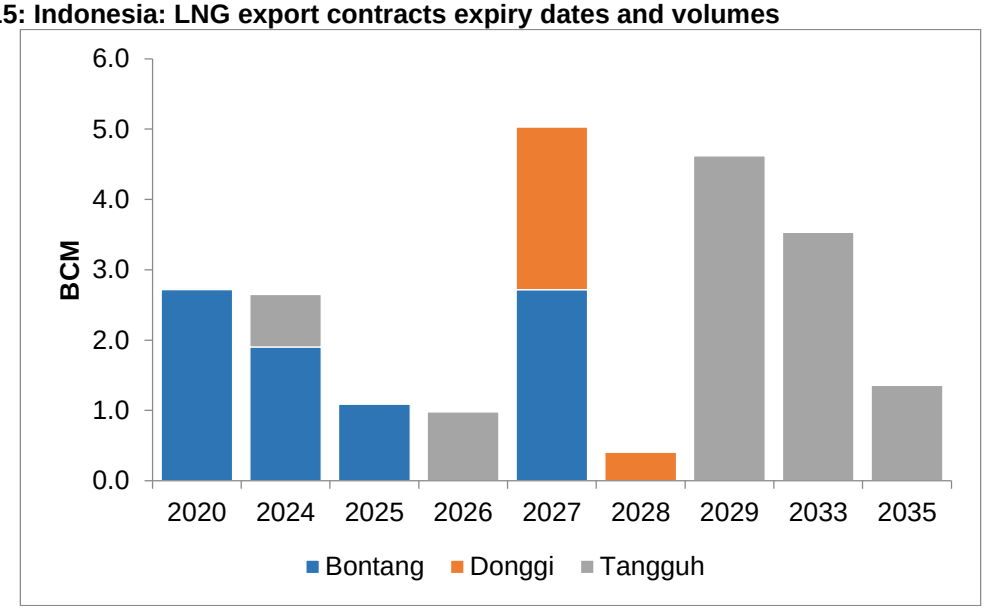
	2017	2020	2030	2040	2050
Production	71.79	70.45	66.34	77.26	83.38
LNG Imports	4.27	10.24	22.66	33.07	40.97
Pipeline Exports	13.34	15.91	0	0	0
LNG Exports	25.59	22.42	32.71	40.63	45.03
Consumption	39.77	42.36	56.29	69.71	79.32

Source: (Fulwood, Gas in South Asia, OIES Internal Seminar 2020)

There are 17.5 BCM of export contracts which will expire between 2020 and 2030 and a total of 22.4 BCM that will have expired by 2035. Those volumes could be diverted to the domestic market, provided that there is sufficient feed gas to sustain LNG production (Figure 15).

[59] https://www.thejakartapost.com/news/2020/02/07/indonesia-to-stop-gas-exports-to-singapore-in-2023.html; https://www.spglobal.com/platts/en/market-insights/topics/oil-gas-2018-outlook-asia

Figure 15: Indonesia: LNG export contracts expiry dates and volumes



Source: Adapted from (GIIGNL, 2020)

President Joko Widodo has announced an ambitious plan to increase electricity capacity to 35,000 MW and install small scale LNG receiving terminals coupled with smaller power plants in 32 locations[60]. This would require investment in excess of USD 23 Billion but has not progressed due to a lack of public funding and interest from investors.

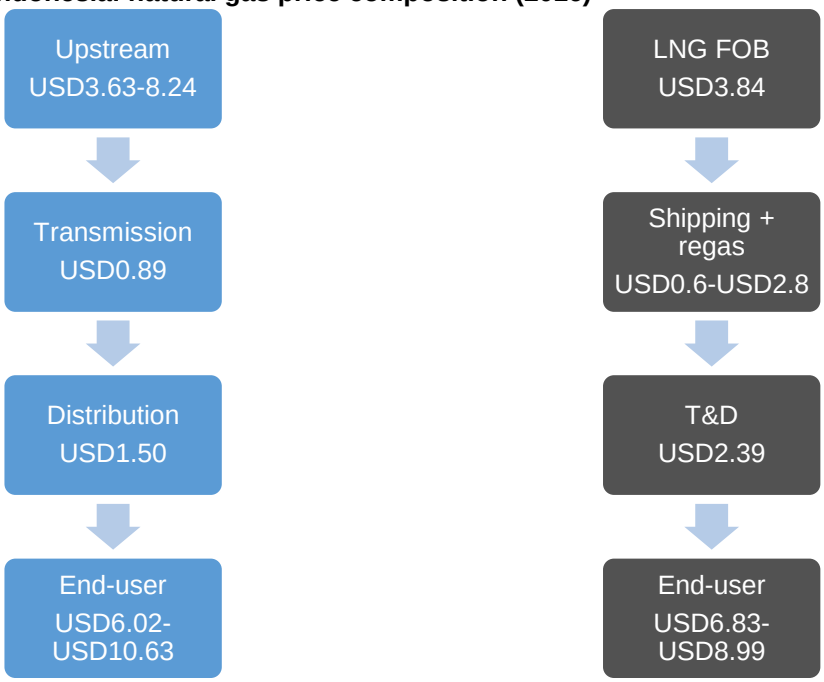
Natural Gas Prices and Subsidies

Domestic gas prices are established through negotiations between buyers and producers with the assistance of SKK Migas, on a field-by-field basis. Historically, domestically produced gas had to be supplied to Pertamina, which then would sell the gas to the end-users. Prices were fixed for the duration of the contract. More recently, under Law No. 22, individual producers can negotiate the terms and sell directly to end users, with assistance from SKK Migas.[61]

The basis for wellhead price negotiation is the Indonesia Crude Price (ICP). Effective from 1 July 2016, the new formula for calculating ICP is ICP= Platt's Dated Brent + Alpha. Alpha is set on a monthly basis and it is calculated based on crude quality, international oil prices and national energy security[62]. As per information available in 2016, end-user gas prices were formed of the following components (in USD/MMBtu, ex-tax), depending whether the source was pipeline gas or domestic LNG (Figure 16).

[60] https://www.rivieramm.com/opinion/malaysia-and-indonesia-plan-for-imports-36251
[61] https://www.pwc.com/id/en/energy-utilities-mining/assets/oil-and-gas/oil-gas-guide-2019.pdf
[62] (KPMG, 2016)

Figure 16: Indonesia: natural gas price composition (2016)



Source: (PwC, 2019)

It should be noted that a substantial component of the end-user prices refers to the use of infrastructure (pipelines and regas terminals). It should be also noted that in 2016 due to the sharp fall of global markets, Indonesia LNG FOB prices[63] were competitive with domestic producer prices. Therefore, in 2016, it would have been advantageous for Indonesian end-users to buy domestically produced LNG. In any case end-user gas prices were considerably higher than prices in Malaysia or South Asia.

Following complaints from large consumers and aiming to boost industrial activity, the Government issued the Presidential Regulation No. 40/2016, stipulating that the Minister of Energy and Mineral Resources (MEMR) could determine lower end-user gas prices for some industrial segments, if gas prices were higher than USD6.0/MMBtu.[64] These segments are fertilizers, petrochemical, steel, rubber glove, glass, oleo-chemical and ceramic. Until 2020 there was not much traction to implement the new policy because the government was unsure on whether to provide direct subsidies or intervene in producers' prices.

In 2017 the Government issued Regulation 45/2017 whereby the MEMR will determine the price of natural gas for power generation based on the following criteria: (a) economics of the gas field; (b) the national and international gas price; (c) the payment capacity of domestic gas consumers, and (d) any additional value deriving from the use of domestic natural gas.

The maximum purchase price of natural gas at the plant gate is set at 14.5% of ICP, meaning that Indonesian large consumers' prices are at international parity. Regulation 45/2017 also establishes that if an IPP or PLN cannot source domestic gas at a price lower than 14.5% ICP then they may purchase domestic or imported LNG[65].

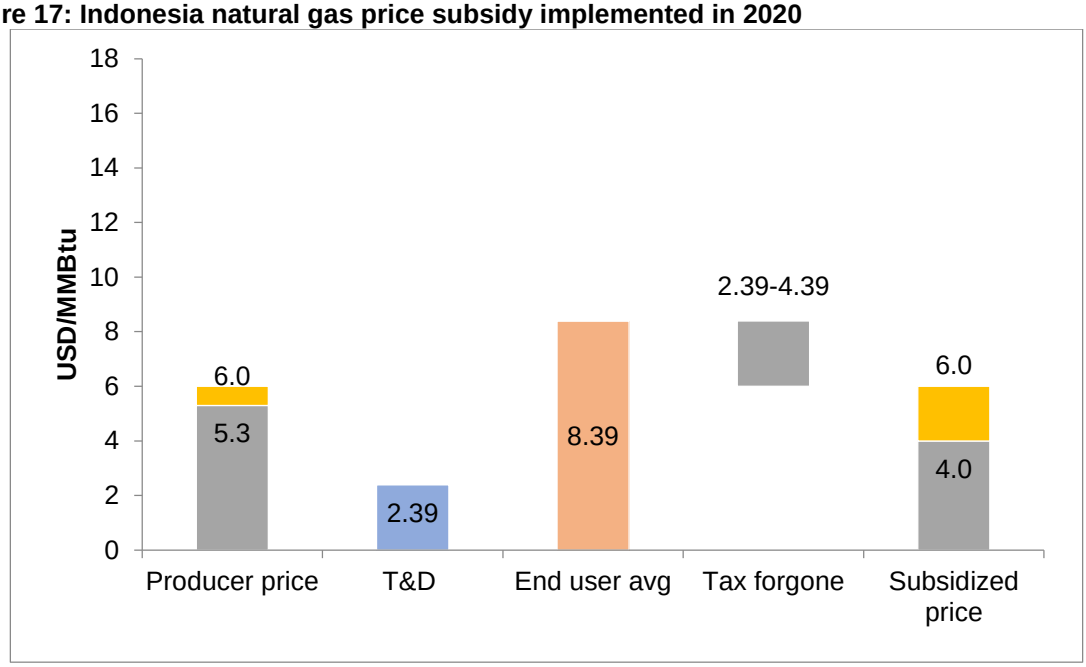
As of January 2020, gas prices for large industrial consumers were in the range of USD8.0-9.0/MMBtu, which prompted further complaints from the press and end-users' trade associations[66]. In April 2020,

[63] Basically from Bontang and Tangguh
[64] (PwC, 2019)
[65] (Ginting, 2017)
[66] https://www.thejakartapost.com/academia/2020/01/14/frustratingly-high-gas-prices.html

the Energy Minister signed ministerial decree 8/2020 mandating that four large industrial consumers and seven gas distribution companies should buy gas from producers at prices of respectively USD 6.0 and 4.0/MMBtu for total volumes up to 3.3 BCM/year. The distributors will then sell their volumes at a price of USD 6.0/MMBtu to industrial consumers within their transmission and distribution networks. The subsidy will be provided by the Government through forgone state-tax revenues charged to upstream producers. The mechanism is valid from 2020 to 2024.

The mechanism is illustrated on Figure 17 below. The average end-user price as of early 2020 was USD 8.0-8.39/MMBtu, whereas producer prices ranged from USD 5.33-6.0/MMBtu. The new price implies subsidies ranging from USD 2.39 to USD 4.39/MMBtu. Government sources estimate that the forgone tax revenue amounts to USD 804 million.

Figure 17: Indonesia natural gas price subsidy implemented in 2020



Source: adapted from (The Jakarta Post, 2020)

In 2017 the Government decided to freeze electricity tariffs, initially until the end of 2019, due to sluggish economic growth and in tandem with the upcoming presidential elections. The Government also decided to cap the price paid for coal resulting from Domestic market obligation at USD 70/ton[67], as of March 2018.

If the mismatch between end-user electricity tariffs and gas/coal prices continues, there is a risk of lack of investment in the development of domestic natural gas and of aggravating potential consequences of the May 2020 approval of the gas price incentive mechanism, which are summarized in the next section.

Key insights

Indonesia's plans to boost domestic gas production have not provided sufficient incentives to attract more investment in exploration and development. Relative progress has been made in blocks prone to supply Bontang LNG, but not in sufficient volumes to restore its previous liquefaction capacity.

Indonesia's government is planning to treble gas demand in the period 2020-2040 boosted by industry and power to a lesser extent. Even using more conservative demand forecasts, domestic gas supplies

[67] https://theinsiderstories.com/indonesia-caps-coal-prices-for-power-at-us70/

will be complemented by further reductions in LNG and pipeline exports. By 2030 nearly half of the domestic market will be supplied by LNG diverted from Indonesia's liquefaction plants.

The implementation of a gas price cap of USD 4.0-6.0/MMBTU for a group of large consumers helped by forgone tax revenues might be the beginning of a new era of price subsidies. Besides the pressure on public finances, this would further discourage domestic exploration because there will be no incentive to allow for the development of more expensive gas fields.

If the same measures apply to LNG diverted into the domestic market, this would result in negative netback LNG FOB prices at a liquefaction plant of USD -0.83-2.99/MMBtu. This would result in subsidies/losses

of USD 170-600 million per annum, for a volume of 67 cargoes diverted to the domestic market. These figures were calculated before the drastic drop in oil prices in the first quarter of 2020.

If oil prices continue to float around USD 50-60/barrel over the next 2-3 years, the diversion of Asian bound cargoes to the domestic market would entail losses of hard currency revenues in excess of USD 7.0/MMBtu for export contract prices at 14.5% Brent. However, this would still be cheaper than importing fuel oil to supply power and industries - at prices above USD 10.0/MMBtu.

If subsidies to other consumers also ramp up, there will be a strong burden either on the Government or on Pertamina's finances – similar to what happened in Malaysia with Petronas. As domestic gas resources become depleted and LNG prices gradually return to pre-2019/2020 levels, gas imports might become unaffordable.

Indonesia might need to resort to increasing the utilization of coal and renewables to meet power and industrial demand. In fact coal-fired power generation is already expected to double from 19.53 GW in 2017 to 39.39 GW in 2027 whereas gas fired capacity rises from 12.1 to 26.4 GW in the same period.

As Indonesia's LNG export contracts expire between 2021 and 2035, the volumes are likely to be diverted to the domestic market. If ageing gas fields supplying the LNG plants are not rejuvenated or new discoveries are made, LNG output will decline further and the country will need to resort to actually importing LNG from other countries.

As a conclusion, the combination of a) maturing fields and unattractive fiscal terms in the upstream pulling down production; b) rising population and industrialization pushing domestic demand, and c) increased pressure from government stakeholders to subsidize energy prices has been the main reason why Indonesia shifted from gas exporter to LNG "importer". This shift is prone to accelerate in the next decade and the country is bound to lose its current role as an important supplier in the Asian LNG market.

Argentina

Context and evolution

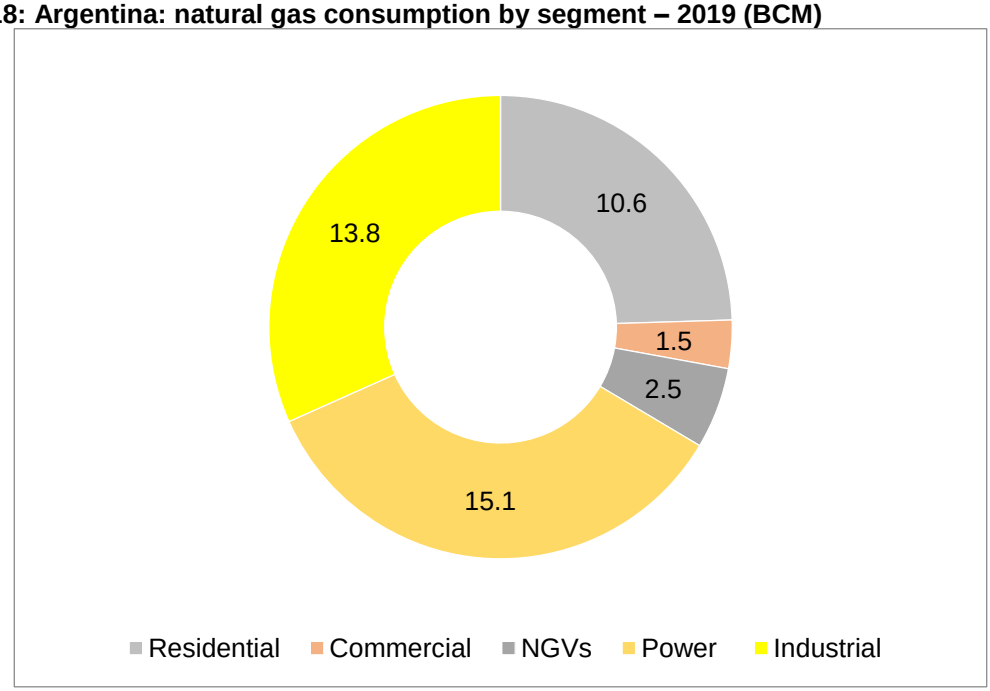
Argentina is currently the largest natural gas market and producer in South America. In 2019 Argentina's gas consumption reached 43.4 Bcm/year, down from 44.7 Bcm/year in 2017.[68] Natural gas accounts for more than 50% of Argentina total energy consumption.

Argentina's gas market is quite distinctive from other regional markets in South America because a large share of the consumption, circa 25.5%), arises from the residential sector (Figure 18), compared to only 1.8% in Brazil. This is because Argentina endures colder winters, requiring energy for space heating. Therefore the former gas incumbent, Gas del Estado, built a comprehensive gas distribution network to supply residential areas, predominantly in Buenos Aires province. Residential demand is

[68] (Ministerio de Minas e Energia - Brazil, 2019)

very seasonal and is responsible for most of the country's winter/summer swing. For example in July 2019 the average daily consumption was 149.7 MM m^3/day versus 101.6 MM m^3/day in March 2019.[69]

Figure 18: Argentina: natural gas consumption by segment – 2019 (BCM)



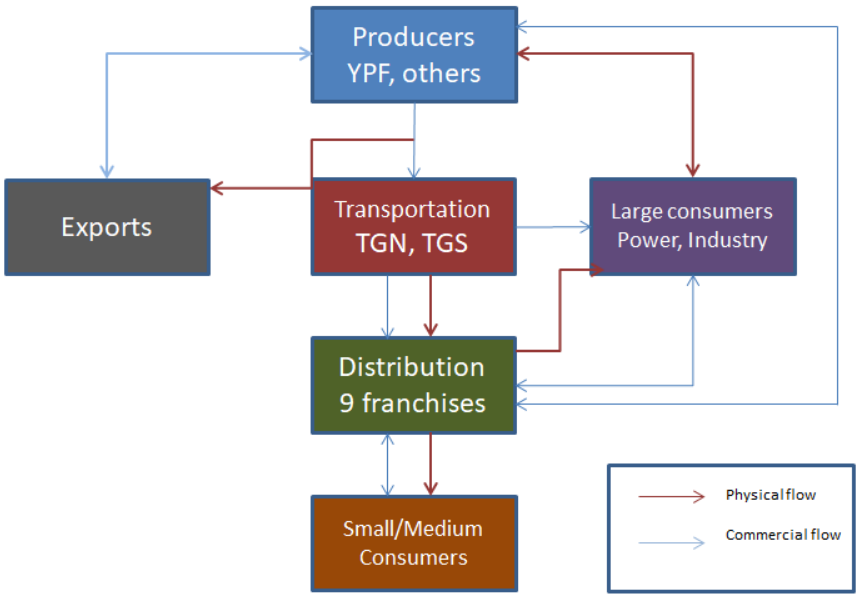
Source: (Ministerio de Minas e Energia - Brazil, 2019)

Argentina was the first country in Latin America to undergo a comprehensive restructuring of the natural gas and oil markets, led by a chronic shortage of funds from the government to invest in the upgrade and expansion of upstream and downstream infrastructure.

In the period 1992-1994 the national oil and gas company (YPF) was initially restructured and then privatized and the state monopoly gas company (Gas del Estado) was unbundled into eight distribution and two transportation gas companies, which were subsequently privatized.[70] International companies, such as British Gas, Enron, Nova (Canada), Gas Natural, and Tractebel became operators of the T&D companies. The reform also allowed for the removal of wellhead and wholesale price controls, the establishment of a third-party open access regime for transportation pipelines, and the creation of an independent regulatory authority, ENARGAS.[71] The gas distribution companies' exclusive franchise was restricted to consumers using less than 10,000 m^3/day, so large consumers could buy natural gas directly from producers (Figure 18).

[69] (Ministerio de Minas e Energia - Brazil, 2019)
[70] The government also allowed for a ninth greenfield gas distribution concession
[71] (OECD, 1998). Enargas = Ente Nacional Regulador del Gas

Figure 18: Argentina: Configuration of the Argentine gas market after 90's restructuring



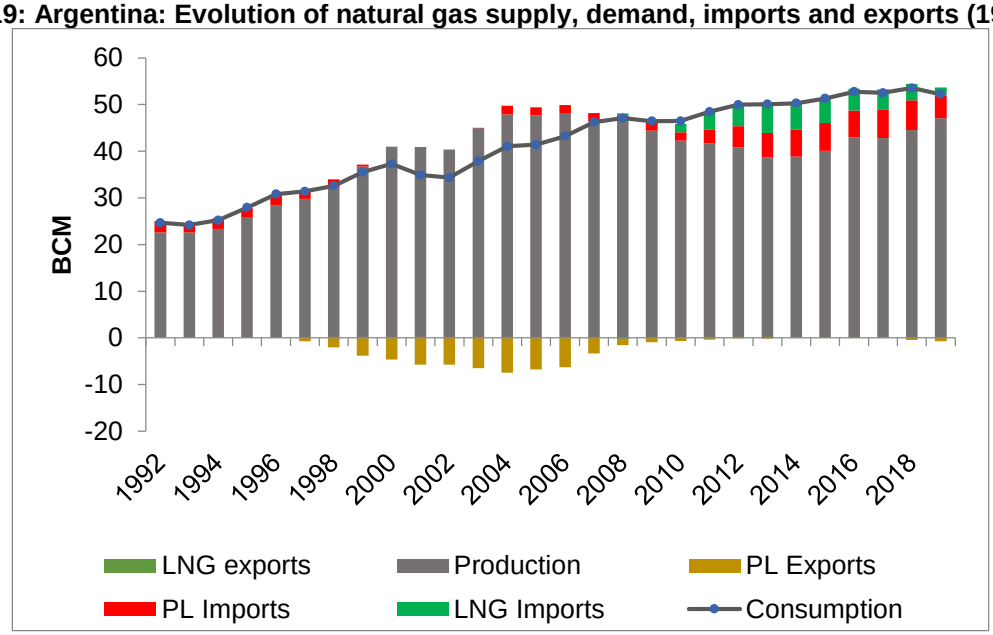
Source: Author adaptation of (Brandt, et al., 2016)

Although there were many upstream producers operating in Argentina, YPF (acquired by Repsol) remained and remains the largest oil and gas producer in the country.

The dynamics of natural gas imports and exports

Over the last 25 years Argentina evolved from a self-sufficient and exporting gas country to an LNG/pipeline importer followed by the current and brief phase of seasonal gas and LNG exporter. Figure 19 shows the evolution of the supply demand situation since the beginning of the market reforms in the 90's.

Figure 19: Argentina: Evolution of natural gas supply, demand, imports and exports (1992-2019)



Source: (IEA, 2019)

The main reasons for such dynamics can be summarized as follows;

- Argentina is endowed with large gas resources but until 1992-1995 those resources were mostly controlled by government entities with limited investment capacity. As a result the market was balanced but could not grow further.
- The liberalization and privatization of the sector, coupled with a relatively stable currency allowed for private investment in exploration, development and infrastructure, leading to increased production and exportable gas surplus.
- The collapse of the parity Argentine Peso: USD and Government intervention in prices and tariffs led to fast growing consumption and a slow-down in upstream investment.
- Further government intervention, imposing high tariffs on exports, led to the suspension of pipeline exports, an increase in volumes imported from Bolivia, the commissioning of two LNG import terminals and seasonal pipeline imports from Chile.
- As LNG and gas imports debilitated Argentina's finances, another Government intervention providing higher than end-user prices to unconventional gas production, led to an increase in gas production coupled to seasonal production of small LNG volumes, seasonal pipeline exports to Chile, Uruguay and Argentina and a sharp reduction in LNG imports. Gradual increases in end-user prices reduced the gap between producer and consumer prices.
- In early 2020, in the wake of another financial crisis and a looming foreign debt default, the Government intervened again and froze consumer prices. Investment in gas development has slowed down, which may cause another round of LNG imports.

3. 1992-2001: Market liberalization and private investment

Gas producer prices and tariffs were indexed to the USD bearing a 1:1 Argentine Peso parity with the USD. Producer prices (USD 1.0-1.4/MMBtu in 1998-1999) were discovered as a result of applying a netback calculation from the main consumption region (Buenos Aires) to the main producing basins: Neuquén, Austral and Northwest.

From 1992 to 1995 there was a noticeable increase in development and exploration investment but uncertainty on prices, and changes in the fiscal regime resulted in a subsequent slowdown.

A surplus in production in the Neuquén and Austral basins led to the construction of seven pipelines exporting gas to Chile, Brazil and Uruguay. Due to ongoing political commitments to assist the weaker Bolivian economy, Argentina started importing gas from Bolivia in 1972 on a 20-year supply agreement with volumes around 2.0 BCM/year. This contract has been subsequently extended and expanded until 2026.

4. 2002-2013: End-user price subsidies and swing from gas exporter to gas importer

The 1998 recession followed by the 2001-2002 financial crisis prompted the government to devalue the Argentinian Peso to 1:3.5 of the USD, to abolish any indexation of prices to foreign currencies and renegotiate public service contracts. This resulted in gas basin prices dropping from USD 1.15/MMBtu on average to USD 0.3-04/MMBtu, whereas end-user prices fell to USD 0.40 for industrial and USD 0.66/MMBtu for residential users.[72]

With the heavy fall in producer prices, there was little incentive to invest in exploration but despite the recession, demand continued to increase because gas was a cheaper energy supply than oil products. In the period 2003-2005 natural gas production fell on average by 15%, whereas demand increased by 42%. A freeze in end-user prices was supposed to be a transitory measure but it lasted for more than

[72] (Honore, 2004)

10 years. This was followed by the imposition of a 20% tax on natural gas exports in 2004 and the gradual suspension of all pipeline exports.

In the period 2002-2008, demand increased on average by 5.4% per annum, an additional consumption of 12.7 BCM, equivalent to the entire gas market of Colombia or Singapore.

The rising imbalance of supply and demand, coupled with the export tax resulted in the gradual suspension of pipeline exports, which came nearly to a halt in 2007. In 2008 Argentina became a gas importer, with the commissioning of its first LNG receiving terminal located in Bahia Blanca, owned by YPF, via an FSRU operated by Excelerate. This was followed by a second smaller FSRU closer to Buenos Aires, the LNG Escobar, commissioned in 2011. The LNG terminals were not sufficient to meet the highly seasonal winter gas demand, therefore in the winter months of 2016 and 2017 Argentina imported 0.6 BCM/year of regasified LNG from Chile, achieved by reversing the flow of the former exporting pipelines Norandino and GasAndes.

5. 2013- 2019: Price incentives to producers and gradual end-user price reforms

The discovery of large unconventional gas and oil resources in the Neuquén basin, and most notably the rich shale formation of Vaca Muerta provided new hopes for Argentina's self-sufficiency. The development of unconventional gas was helped by price incentive policies coupled to reforms allowing for increase in end-user prices (as explained in the next section).

Unconventional gas production reached a peak of 36 MMm^3/day in 2019, accounting for 25% of Argentina's gas production. According to the IEA, unconventional gas resources – shale and tight gas - increased their share in the Argentine production mix from 10.3% in 2014 to 35.5% in 2018, around 15.8 BCM/year. Tight gas accounted for 59.5% of the unconventional production whilst shale gas accounted for 40.5%, arising mainly from the Vaca Muerta formation.[73]

- In 2018 Argentina resumed seasonal pipeline exports to Chile, with volumes of circa 0.48 Bcm during 8 months of the 2019 spring/summer season. The Energy Ministry also approved seasonal gas exports to Uruguay and Brazil.
- In November 2018 the Excelerate Exemplar FSRU departed from Bahia Blanca. Argentina is currently only importing smaller LNG volumes at the Escobar terminal. In May 2019 Argentina started producing seasonal LNG via a small liquefaction facility (Tango LNG) moored at the site of the former LNG terminal in Bahia Blanca.

6. 2019-Present: Gas price freeze and economic crisis

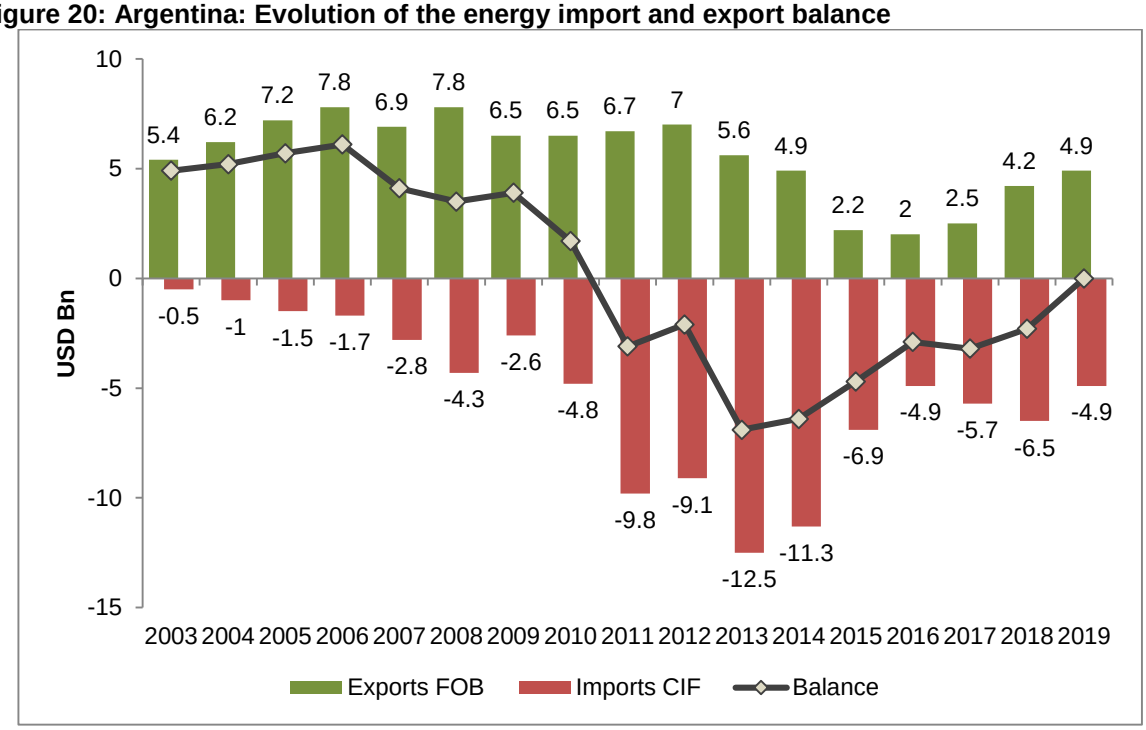
In the wake of the 2019 presidential election and in order to curb inflation, the government intervened and froze gas prices again, causing upstream investment to slow down. The number of rigs in Vaca Muerta dropped from 43 in August 2019 to 29 in December. The collapse in oil prices and the COVID 19 pandemic caused further stoppages with only two rigs active in May 2020. If gas production drops substantially, the country may have to increase LNG or Bolivia gas imports

Argentina natural gas prices and subsidies

According to the Argentine Ministry of Energy[74] subsidies to the energy sector, including electricity, natural gas, LPG and oil products reached a peak of 3.5% of Argentina's GDP in 2014, coming down to 1.4% in 2019.

[73] https://www.infobae.com/def/desarrollo/2019/06/22/argentina-y-el-boom-de-vaca-muerta-de-importador-a-exportador-de-gas/
[74] http://www.energia.gob.ar/contenidos/archivos/Reorganizacion/sintesis_balance/2019-11-20_SE_Subsidios_oferta_y_demanda_de_energia_Argentina_2015-2019_dist.pdf

Figure 20: Argentina: Evolution of the energy import and export balance



Source: (Argentina Secretaria de Gobierno de Energia (b), 2019)

Until 2010 Argentina enjoyed a surplus, albeit declining, in the energy export/import balance, but increased imports of LNG and liquid fuels, coupled with restrictions on exports of oil and natural gas caused a rapid deterioration. In 2013, energy imports reached USD 12.5 Bn, whereas energy exports totalled USD 5.6 Bn, leaving a deficit of USD 6.9 Bn (Figure 20). Such a deficit was extremely detrimental to Argentina's foreign currency reserves.

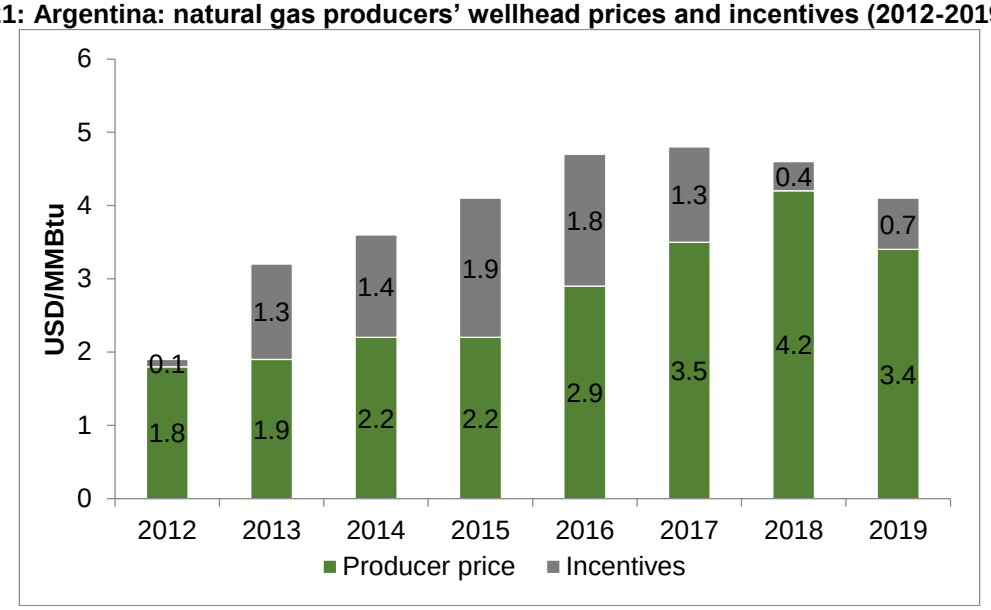
In addition to an increasing gap between energy imports and exports, energy subsidies continued to grow, rising to USD 18.98 Bn in 2015, of which USD 4.91 Bn were subsidies and incentives given to natural gas producers and end-users. The subsidies have two different components:

- Price incentives to unconventional gas producers
- Price subsidies to end-users.

The low prices received by the gas producers until 2012 were the most significant reason for the fall in natural gas production. The implementation of Plan Gas 2013, during Cristina Kirchner's time in government complemented the low baseline prices by "incentives" to increase production above an agreed baseline. This was followed by other plans - "Gas Plus" (I, II and III) – which were continued under a revised timeline during Mauricio Macri's government. The new timeline established that unconventional gas producers would be paid USD 7.5/MMBTU in 2018, dropping USD 0.50/MMBTU per annum until 2021 when it should go down to USD 6.0/MMBtu.

Figure 21 displays the increase in price incentives which reached a peak in 2015, followed by a gradual recovery in conventional gas prices, and the reduction in the average amount of incentives to producers achieved in 2019. In 2015 incentives accounted for 46% of the prices paid to producers, falling to 17% in 2019.

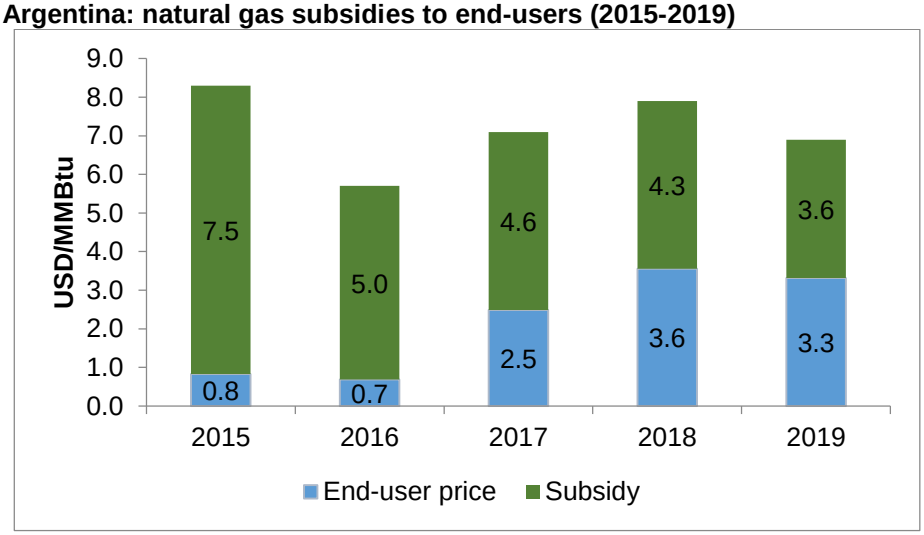
Figure 21: Argentina: natural gas producers' wellhead prices and incentives (2012-2019)



Source: (Argentina Secretaria de Gobierno de Energia (a), 2019)

The subsidies to end-users resulted in a combination of higher supply prices, caused by high LNG and liquid fuels imports and frozen/below-cost prices for residential, commercial and industrial consumers. According to the Ministry of Energy, prices paid by end-users represented only 10% of the actual cost of supply in 2015 (Figure 22).

Figure 22: Argentina: natural gas subsidies to end-users (2015-2019)



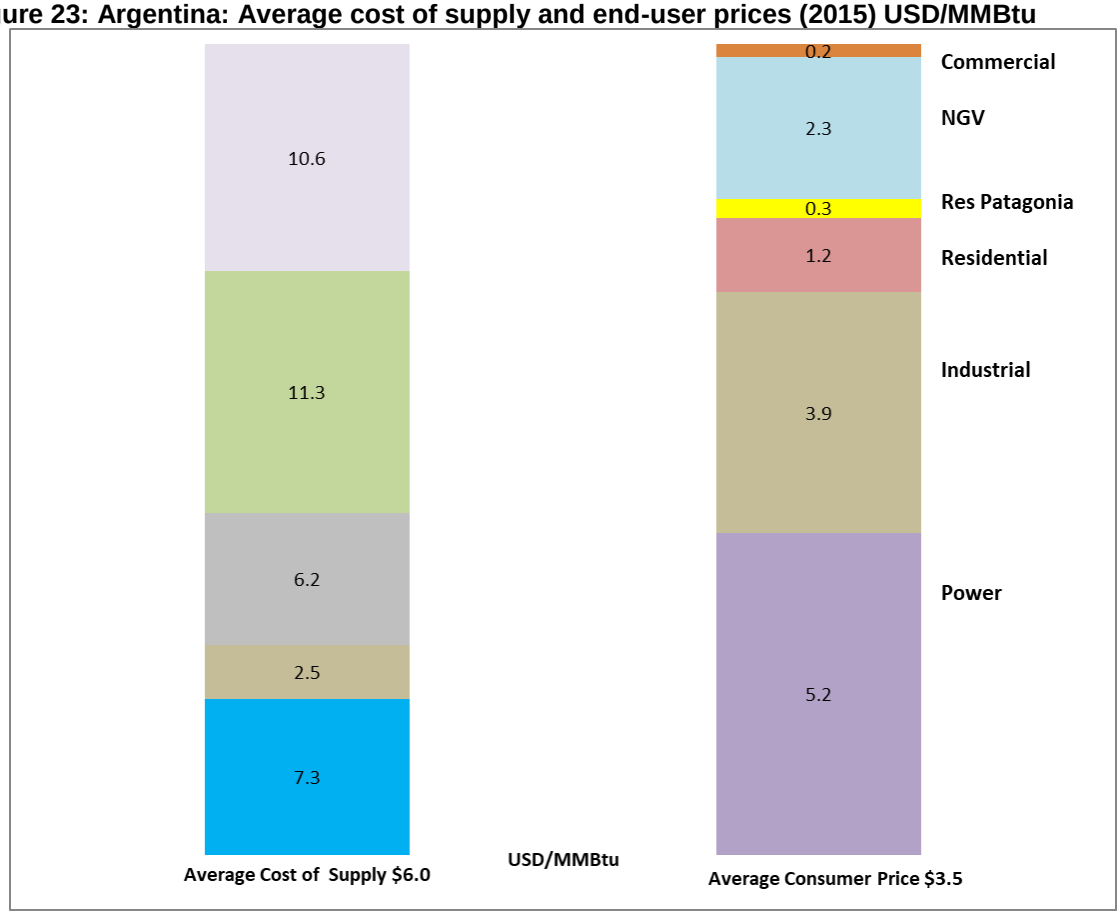
Source: (Argentina Secretaria de Gobierno de Energia (a), 2019)

The reduction in end-user subsidies was achieved by increasing gas prices for residential and commercial consumers, from USD 0.2-1.2/MMBtu in 2015 to USD 2.1-3.7/MMBtu in 2019. Industrial consumers have not had price increases, paying around USD 3.9-4.1/MMBtu, which is far less than the prices paid by similar consumers in Brazil - on average USD 15.35/MMBtu for large industrial consumers[75].

[75] (Ministerio de Minas e Energia - Brazil, 2019)

In 2015 the average cost of supply was USD 6.0/MMBtu, whereas the average end-user price was USD 3.5/MMBtu, implying price subsidies of USD 2.5/MMBtu (Figure 23).

Figure 23: Argentina: Average cost of supply and end-user prices (2015) USD/MMBtu

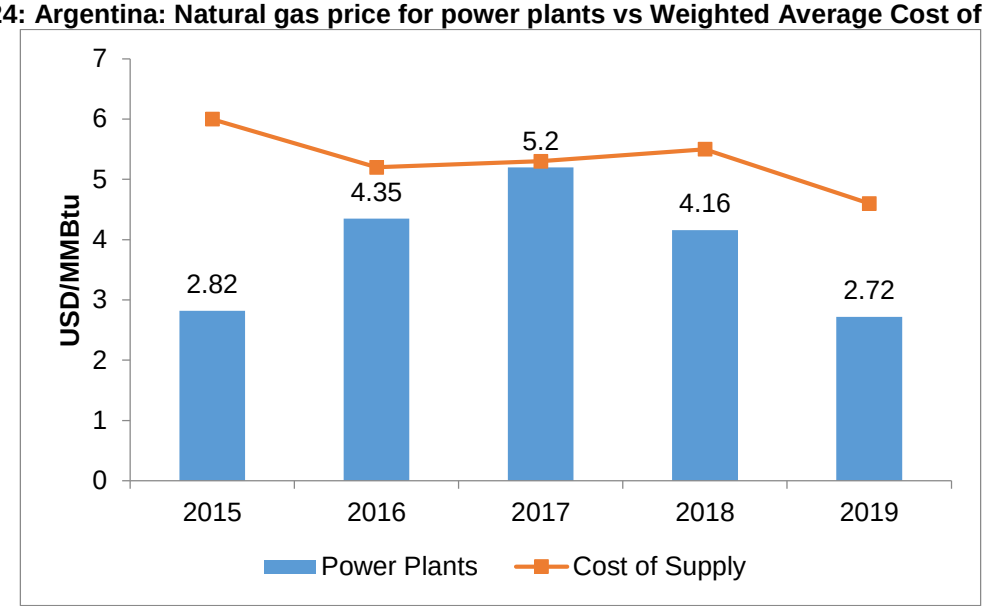


Source: (Argentina Secretaria de Gobierno de Energia (a), 2019)

By 2019 domestic producer gas prices have come down from USD 6.0/MMBtu to USD 4.6/MMBtu, due to a combination of gradual phase-out of incentives to domestic producers, lower imports of LNG and liquid fuels and increased productivity. In the meantime end-user prices increased on average from USD 3.5/MMBtu in 2015 to USD 3.7/MMBtu in 2019, implying a subsidy of USD 0.9/MMBtu, totalling USD 1.39 Bn in 2019.

Although this was a significant progress, the price of gas supplied to power plants has come down to USD 2.72/MMBtu, which is indeed below the cost of supply (Figure 24).

Figure 24: Argentina: Natural gas price for power plants vs Weighted Average Cost of Supply



Source: (Argentina Secretaria de Gobierno de Energia (a), 2019)

The LNG share in the supply mix has come down from 11% in 2015 to 4% in 2019. Bolivian gas supplies still account for 11% of Argentina's supplies, at prices of USD 6.2/MMBtu in 2015, and USD 6.7/MMBtu in 2019.

According to Argentina's Ministry of Energy, subsidies have come down to USD 5.95 Bn (energy) and USD 2.22 Bn (natural gas) by the end of 2019[76], a significant achievement when compared to 2015 figures of USD 18.98 Bn (energy) and USD 4.91 Bn (natural gas).

Natural gas demand scenarios

In 2019 Argentina's domestic gross production rose to 49.3 BCM, of which 39.5 BCM was available for sale. Gross production of unconventional gas (tight and shale) reached 21 BCM against 16.6 BCM in 2018, an increase of 26% year on year.[77]

Despite this remarkable progress, there are question marks on whether this level of production will be sustainable during and after the Argentine economic crisis. Uncertainties created by the government "temporarily" freezing domestic energy prices and limiting foreign remittances in 2019, have been compounded by the sharp drop in oil prices in the first quarter of 2020. According to information released by the Argentine Institute of Petroleum and Gas (IAPG) there was a drop of 12% in the number of wells drilled in 2019 to 905, compared to 1030 wells drilled in 2018.[78] Sources from the local industry believe that Vaca Muerta development is not economical below oil prices of USD 40-50/barrel[79].

Energy experts estimate that Argentina needs investment of USD 102 billion over the next 10 years to allow Vaca Muerta to achieve its full potential: USD 100 billion for upstream development, USD 2 billion for the gas pipeline and USD 5 billion for the LNG terminal.[80]

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[76] (Argentina Secretaria de Gobierno de Energia (a), 2019)
[77] https://www.infobae.com/economia/2020/02/28/vaca-muerta-el-crecimiento-de-la-produccion-registrado-en-2019-se-transformo-en-caida-y-conflictividad-laboral-en-2020/
[78] http://www.vacamuertanews.com.ar/ver_noticia.php?id=20200222001301
[79] https://elpais.com/economia/2020/02/27/actualidad/1582832498_041823.html
[80] (Brandt, et al., 2016); https://www.spglobal.com/platts/en/market-insights/latest-news/oil/122619-feature-argentina-faces-big-challenges-to-develop-vaca-muerta-for-export-growth

In order to improve their returns and ensure USD-based revenues, the producers have requested the possibility of exporting more gas; however, the export duty of 8% hampers[81] their competitiveness. Producers have expressed concerns about the change in the incentive policies and are cautious about future investment.[82] The natural gas rig count fell from 13 in July 2019 to only two in June 2020.

Natural production in Vaca Muerta has also been choked by lack of sufficient pipeline infrastructure connecting Neuquén to the main consuming regions around Buenos Aires. The Neuquén-Salliqueló-San Nicolas pipeline is projected to transport initially 5.5 BCM/year and this could be expanded to 14.6 BCM/year.[83] The first phase of the project, totalling 570 km would cost USD 800 million and was expected to start operations in May 2021, to allow for the replacement of winter LNG imports at Escobar. The second phase, 473 km, would start operations by 2024. In total the project would require USD 2.0 Bn[84]. Due to the oncoming presidential elections, and uncertainties on gas policies and project financing, the tender for the first phase was postponed from 12/09/2019 to 31/03/2020.[85]

In addition to serving the domestic market, the pipeline would be instrumental in the construction of an LNG export plant in Bahia Blanca allowing Argentina to earn USD-denominated revenues.

Tango LNG is a small FSRU chartered by YPF from Exmar on a 10-year contract, with storage capacity of 16,100 m^3 of LNG and liquefaction capacity of 0.9 BCM/Year.[86] The vessel was originally built to serve a project in Colombia which did not materialise. It is currently based in Bahia Blanca and delivers LNG to a 25,000 m^3 ship (Fuji LNG), which then feeds Excelerate's 138,000 m^3 LNG vessel Excalibur. The whole operation takes 45 days. In summer, LNG will be exported to international markets, whereas in winter it will be uploaded at the Escobar terminal, thus providing hard currency revenues. In 2019 YPF exported 0.08 BCM via Tango and they aim to export 8 cargoes in 2020.[87]

YPF is currently mulling the development of a large-scale LNG export facility. In July 2019 it awarded a pre Front End Engineering Design (pre-FEED) contract to McDermott for a 5-10 mtpa LNG facility for shale production in Vaca Muerta[88].

The Secretariat of Energy has produced two supply/demand forecasts, with and without LNG exports, respectively high and low case scenarios. In the high case scenario a total peak supply of 275 MM m^3/day is estimated by 2030, including supplies from conventional and unconventional gas and imports from Bolivia. Under this scenario gas exports would follow a seasonal profile, with circa 4-8 BCM/year available to produce LNG. The proposed concept is to build a 2-phase project, initially 5 mtpa, growing to 10 mtpa 5 years later.

The concept involves a seasonal LNG plant, with a utilization factor of 80%. The plant output would be reduced during Argentina's winter season (summer season in the northern hemisphere).

The high seasonality of Argentina's gas demand inhibits the availability of exportable volumes in the period May-August as shown in Figure 25 below.

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[81] Until December 2019 it was 12%

[82] https://www.petroleum-economist.com/articles/upstream/exploration-production/2019/economic-crisis-threatens-to-stall-vaca-muerta

[83] https://econojournal.com.ar/2019/07/los-principales-ejes-del-pliego-de-construccion-del-gasoducto-de-vaca-muerta/

[84] https://www.lanacion.com.ar/economia/licitan-gasoducto-buenos-aires-potenciar-vaca-muerta-nid2272638

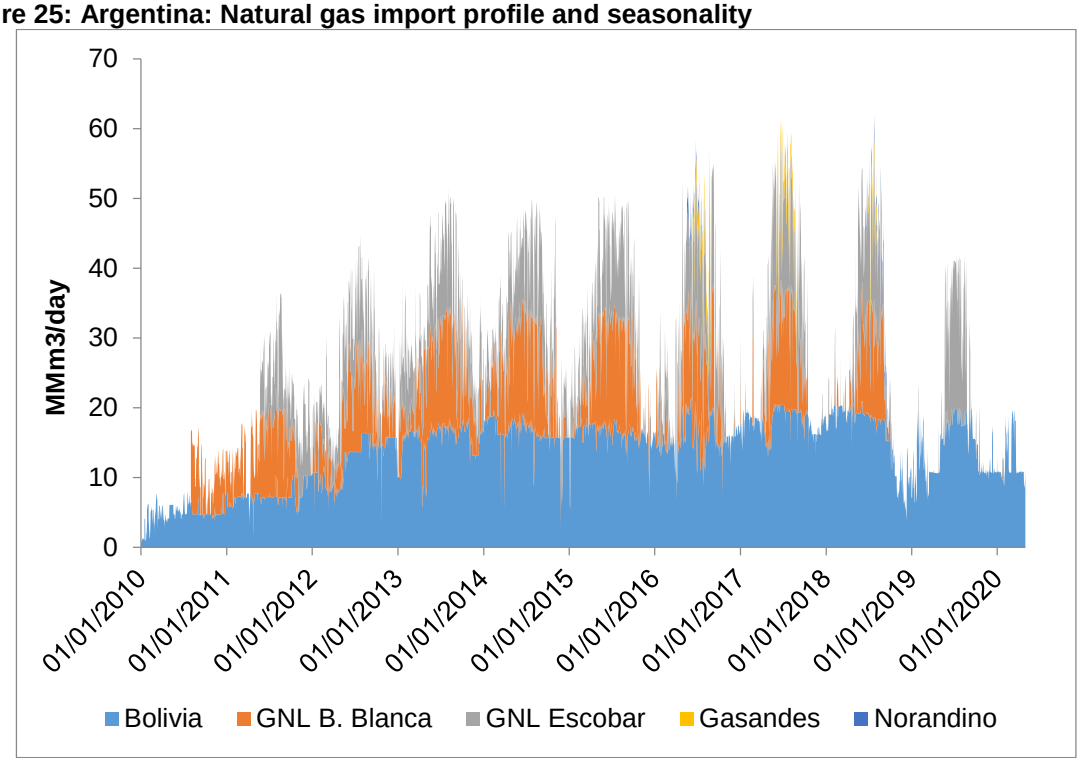
[85] https://www.cronista.com/economiapolitica/Llaman-hoy-a-la-licitacion-para-el-nuevo-gasoducto-de-Vaca-Muerta-20190730-0055.html

[86] https://www.lngworldnews.com/exmar-completes-commissioning-of-tango-flng/

[87] https://energiaenmovimiento.com.ar/argentina-y-el-mercado-del-gas-volver-a-exportar/

[88] http://www.mcdermott-investors.com/news/press-release-details/2019/McDermott-Awarded-Pre-FEED-Contract-by-YPF-for-Vaca-Muerta-LNG-in-Argentina/default.aspx

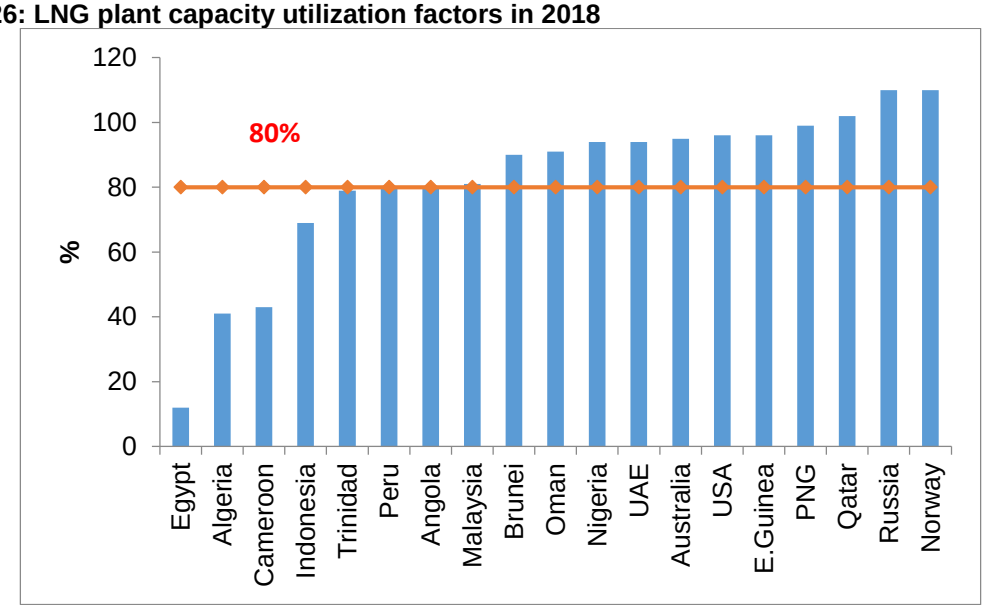
Figure 25: Argentina: Natural gas import profile and seasonality



Source: ENARGAS, 2020

This would be a rather unusual scheme, because the most competitive LNG plants operate under a capacity utilization factor above 90% (Figure 26). There are a few plants operating at or slightly below 80% but in general such plants were commissioned a long while ago and have been mostly amortized, as is the case of Malaysia and Trinidad. Others have had gas supply discontinuities, such as in Indonesia. In most cases the LNG plants elsewhere benefit from the added revenues from liquids. In the case of Argentina, it seems that the liquids will be removed in the gas processing plants in Neuquén, thus not benefiting the economics of the proposed LNG plant.

Figure 26: LNG plant capacity utilization factors in 2018



Source: (IGU, 2019)

Assuming liquefaction costs of USD 750-1000/tonne at 80% capacity utilization, and a range of LNG prices and shipping costs for LNG delivered in Japan and northern Europe (TTF) and assuming a transportation tariff of USD 0.8/MMBtu for the pipeline Neuquén-Bahia Blanca, the netback to the producers would range from USD -0.2 to 2.1/MMBtu (Table 5).

If, instead of building the LNG plant the available surplus production is exported to Chile, Brazil and Uruguay, which are already interconnected to Argentina via existing pipelines, and assuming that those markets would pay international parity prices of USD 6.0/MMBtu, the Argentinian producers would benefit from a much higher netback, around USD 4.7/MMBtu.

In the case of exports to Chile, it might be possible that the Chilean buyers would not have to pay the pipeline tariff Neuquén-Bahia Blanca, because the export pipelines are located west of Vaca Muerta. In such case the netback to volumes exported to Chile could be as high as USD 5.5/MMBtu.

It is also worth note that in 2004, Argentina exported 7.5 BCM to those three countries, and therefore there is sufficient export capacity in the existing pipelines. The big issue is that Chilean, Uruguayan and Brazilian buyers might not be able to accommodate the seasonal supply swings proposed by Argentina.

Table 5: Argentina: LNG and pipeline netback prices to Vaca Muerta (Neuquén)

	LNG Bahia Blanca[89]		**Pipeline exports**
	TTF	Japan (JKM & 12%Brent)	Chile, Brazil, Uruguay
Destination price	4.7-5.6	4.8-6.2	6.0
Shipping costs	0.4	0.6	0
Liquefaction costs *	2.7-3.6	2.7-3.6	0
PL Neuquén-Bahia Blanca	0.8	0.8	0.8
Existing export PL	0	0	0.5
Netback producer	-0.2-1.6	-0.2-2.1	4.7

Source: Author estimates based on (Ministerio de Energia y Mineria, 2019), (Gas Andes, 2006), (Argus Media, 2020)

Key insights

Argentina is dotted with large reserves of high quality unconventional hydrocarbons, located in a region with significant transportation infrastructure, the Neuquén basin. However, the continuing end-user price freeze and high above surface production costs have resulted in another cycle of subsidies and incentives, which have been partially reduced in the period 2015-2019 at the cost of great government unpopularity.

Although Argentina has been a pioneer of gas market restructuring and early liberalization, its supply and demand imbalance is a typical case of the yoyo effect created by government intervention both on producers' and end-user prices, inflating demand, creating inefficiencies and discouraging investment in exploration and development. Over a period of 15 years the country has evolved from self-sufficiency to import dependency and has more recently returned to an export mode, which seems to be short lived, as a result of a new cycle of price freezing, taking place since December 2019.

Despite great gains in productivity, price incentives for unconventional gas are still required by the producers. In 2019 alone direct incentives to unconventional gas were in excess of USD 400 million. For 2020 and 2021 producer prices for new production of unconventional gas are considerably above international prices, respectively USD 6.5 and 6.0/MMBtu. When and whether unconventional gas accounts for 50% of domestic production, the average cost of production might rise to USD

[89] https://www.cmegroup.com/trading/energy/crude-oil/brent-crude-oil_quotes_globex.html

4.7/MMBtu[90], therefore above average consumer prices of USD 3.7/MMBtu, necessitating subsidies and incentives of USD 2.0/MMBtu, equivalent to more than USD 3 Bn per annum.

One can expect further delays in the construction of the first phase of the Neuquén pipeline, because it seems unlikely that the government could contribute USD 400 million from the Sustainability Fund because of current difficulties in obtaining additional funding and equity. In which case, LNG imports at Escobar should continue. In 2019 IEASA spent circa USD 329 million[91] to import 1.74 BCM of LNG. Also the delay in pipeline construction will result in increased dependency on Bolivia exports. In 2019 Argentina imported 4.9 BCM from its neighbour country.[92]

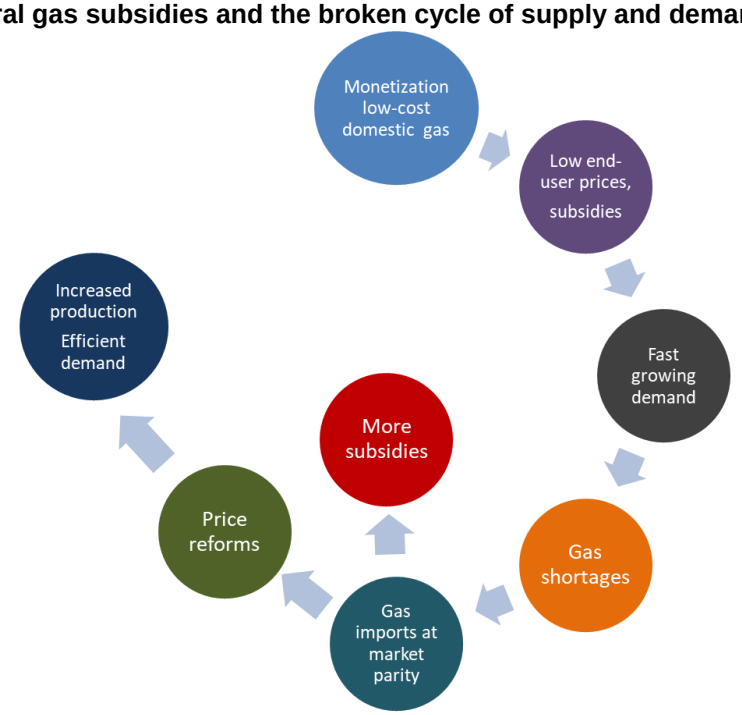
At forecast LNG prices of USD 4.7-6.2/MMBtu DES, the netback to Vaca Muerta producers would be very low and may not remunerate the investment on the LNG plant. It is also difficult to envisage how Vaca Muerta well head prices will come down from USD 6.0/MMBtu to less than USD 2.0/MMBtu in order to compete with USA, Australia and Qatari LNG prices. It might be more attractive to export gas to neighbour countries using the existing pipeline infrastructure. However, Argentina's credibility as a long term supplier needs to be re-established with the market again.

Conclusions

The cases of Malaysia, Indonesia and Argentina highlight the negative impact of government intervention and price subsidies on the energy market. Countries erstwhile self-sufficient and with surplus gas for exports gradually become net gas importers, creating an additional burden to the national oil companies' finances and to the national economy.

Figure 27 below illustrates the cyclic nature of continuous government intervention and subsidies to natural gas prices. There are two potential paths once the cycle starts, but quite often governments choose to maintain the subsidy burden, to avoid unpopular decisions on energy price increases.

Figure 27: Natural gas subsidies and the broken cycle of supply and demand



Source: Author, based on countries' natural gas evolution

[90] Assuming unconventional gas well-head prices at USD 6.0/MMBtu
[91] http://www.ieasa.com.ar/index.php/detalle-de-licitaciones-gnl-escobar-2019/?lang=en
[92] https://www.enargas.gob.ar/secciones/transporte-y-distribucion/partes-diarios-exp-imp-consulta.php?tipo=importaciones

Subsidies to natural gas prices are deemed to cause the following distortions:

- Aggravation of fiscal imbalance
- Misallocation of scarce government funds, diverted from other social priorities, such as health and education, to fund ever growing subsidies
- Financial losses and decapitalisation of the national oil company
- Under-investment in exploration and production of hydrocarbons
- Discouraging energy conservation and promoting wasteful consumption
- Promoting unsustainable energy intensive industrialisation underpinned initially by low gas and electricity prices
- Fostering fast depletion of national gas reserves which results in energy shortages and the need for imports at higher international prices

In common, the three countries display the following features:

- Governments have stated objectives of providing cheap energy to underpin industrialization and keep inflation at lower levels.
- Continuous intervention of the government on consumer prices, replacing old tradition of fuel replacement parity.
- There are several players in the upstream business but the national oil company accounts for most of the production output.
- Well head prices are negotiated between producers, government and national oil companies, but as those prices rise with inflation or indexation with oil prices the government tends to intervene with caps and price freezes.
- Existing gas fields start to mature and deplete; additional gas resources are either further away from demand centres and/or expensive to produce (shale, deeper, acid, marginal), requiring higher well head prices and development of additional transmission infrastructure.
- Floating LNG terminals are a fast track response to unpopular gas shortages.

In the case of Malaysia and Indonesia, although production still exceeds domestic demand the remoteness of the main gas production fields from the populous areas and the lack of viable connecting pipeline infrastructure also played a vital role in the development of LNG receiving facilities. The supply of growing domestic demand is gained through reductions in gas exports, and balanced with imports.

In the case of Malaysia and Indonesia, increasing power demand has been met through an increasing participation of coal in the generation mix, with renewables playing a small but increasing role from 2020 onwards. Indonesia is currently the third largest producer of coal, behind China and the USA, therefore there is an abundant supply of cheap coal to feed domestic and neighbouring country demand. In 2019 the consumption of coal rose respectively by 13%, 9.4% and 7.7% in Argentina, Malaysia and Indonesia.[93]

In Malaysia, Petronas opted to maintain the existing and valuable LNG export contracts, but is importing LNG from its Gladstone LNG plant in Australia and from Brunei, the former mostly to meet contractual obligations to supply Singapore with lean gas.

In Indonesia, the depletion of the gas resources feeding the Arun LNG plant resulted in the shutdown of the liquefaction plant and its conversion to an LNG receiving terminal. The Bontang LNG plant has reduced its export volumes, partially because it has the obligation to supply the domestic LNG market

[93] (BP plc, 2019)

and also because feed gas production has been falling. Tangguh LNG also has domestic supply obligations which will increase with the commissioning of Train 3.

Over the last 5 years the three countries embarked on end-user price reforms or changes in the upstream fiscal regime aiming at bringing end-user prices closer to market prices and encourage domestic production, with mixed results. Argentina started to phase down subsidies in 2015 whilst Malaysia started implementing price reforms with gradual alignment of domestic with LNG FOB parity in 2015, and Indonesia allowed the pass-through of the costs of domestic gas and LNG FOB to end-user prices. In the case of Malaysia regulated gas prices are now very close to FOB LNG indexed prices. Industrial prices are higher in Indonesia than Malaysia, prompting complaints from large consumers and the imposition of subsidies in 2020. In the case of Argentina the government inaugurated in December 2019 decided to reverse to a price freeze from December 2019.

If Malaysia and Indonesia's future LNG imports are in line with OIES forecasts, this would imply a significant change in the outlook for the supply/demand balance in Southeast Asia. Their combined import needs would reach nearly 40 BCM/year by 2030 and the two countries would lose their status as significant gas/LNG suppliers in the region.

In the case of Argentina, despite the initial impetus in realigning end-user prices and reducing incentives to producers, it seems that the country is about to start a new and déjà vu cycle of heavy governmental interventions, with expected and déjà vu negative impacts on domestic production.

Lower international LNG prices provide an opportunity to stimulate 3rd party imports to countries if terminal and pipeline capacity is effectively available at non-discriminatory tariffs and end-user prices are above cost parity.

For all the three countries, price reforms are essential to restore domestic production, but if it comes too late, because oil and LNG prices are currently quite low, such reforms will not necessarily boost investment in the upstream as oil companies are sharply restricting their CAPEX.

Glossary/Acronyms

Bbl/day: Barrels of liquid per day

BCMÇ Billion cubic metres

BCM/year: Billion cubic metres per year

CAA: Commercial Arrangement Area

CAPEX: Capital expenditure

COP21: Conference of the Parties held in Paris in 2015

DES: Delivered ex-ship

FEED: Front End Engineering Design

FOB: Free on Board

FSRU: Floating Storage and Regasifying Unit

FSU: Floating Storage Unit

GDP: Gross Development Product

HH: Henry Hub

ICP: Indonesia Crude Price

IEASA: Integración Energética Argentina S.A.

IOC: International Oil Company

JDA: Joint Development Area

JKM: Japan Korea Marker

LNG: Liquefied natural gas

MLNG: Malaysia LNG

MMBtu: Millions of BTU

MMm^3/day: Million cubic metres per day

Mtpa: millions of tonnes per annum (of LNG)

MW: Megawatts

MWh: Megawatt hour

RGTP: Regasification Terminal Pengerang (Malaysia)

RGTSU: Regasification Terminal in Sungai Udang (Melaka, Malaysia)

TPA: Third Party Access

TTF: Title Transfer Facility (Netherlands)

UAE: United Arab Emirates

USD: US dollars

WAP: Weighted Average LNG Price (FOB Bintulu, Malaysia)

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