Special Section: LNG Sector in Pakistan – Attaining Sustainability through Deregulation and Structural Reforms[1]

Pakistan is a relatively new player in global LNG market, but has quickly become a major importer. Depleting indigenous gas reserves and a transition towards cleaner and cheaper power generation have been the major factors driving the country towards adding LNG to its energy mix. Over the past few years, the government has established the basic LNG infrastructure, which has helped bridge the gas supply-demand shortfall, and lately there has been some progress towards private sector participation in LNG import. However, multiple operational and structural bottlenecks in the current framework are causing import delays, price distortions, as well as lags and inefficiencies in the distribution of LNG. This section sheds light on some of the international best practices that the government may learn from, and emphasizes the need to introduce reforms to maximize the potential returns from deregulating the LNG market.

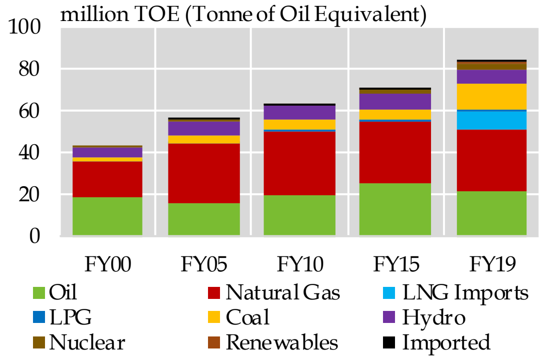
S1.1 Introduction

The objective of this section is to: (i) briefly explain the evolution of global LNG trade; (ii) describe the existing structure of Pakistan's LNG sector; (iii) highlight the structural, contractual and pricing elements that cause delays at the import, transmission, and distribution stages and result in regulatory inefficiencies; (iv) provide an overview of the ongoing deregulation, onboarding of private sector participants, and capacity expansions underway in the domestic LNG sector; (v) evaluate the fundamental concerns associated with natural gas pricing and governance in distribution companies; and (vi) discuss the possible redressal measures to help the overall gas sector operate on a sustainable basis.

S1.2 Background

Natural gas is one of the most important sources fulfilling Pakistan's energy

Primary Energy Supplies by Source in Pakistan **Figure S1.1**



Source: Pakistan Energy Yearbook, HDIP (various editions)

requirements (**Figure S1.1**), primarily because of the country's natural endowment of the fuel, and its inherent cost advantage over oil. Contributing nearly 35 percent of the country's primary energy supplies, local natural gas production currently stands at 29.3 million tons of equivalent (TOE) – placing Pakistan among the top-25 natural gas producing countries.[2] In terms of final energy consumption, the share of natural gas has remained above 30 percent over the past

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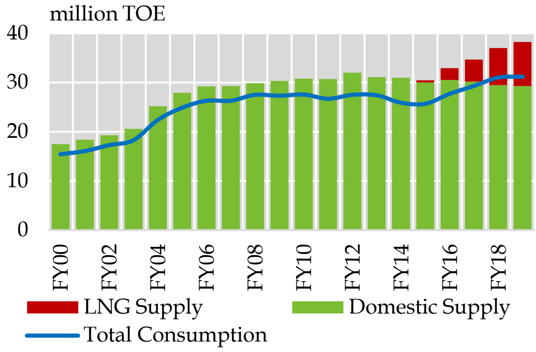
[1] This chapter draws heavily from discussions with, and the data shared by, officials from the Ministry of Energy (Petroleum Division), Sui Northern Gas Pipelines Limited, Oil and Gas Regulatory Authority, Pakistan, Hydrocarbon Development Institute of Pakistan, Pakistan LNG Limited, and Engro Elengy.
[2] BP (2019). Statistical Review of World Energy 2019. London: British Petroleum.

two decades. Thermal power producers, households and general industries are major users of natural gas, while the fertilizer sector also uses it as a principal feedstock and fuel source.

However, despite a large and growing consumer base, indigenous gas supplies have stagnated since 2008. While security concerns in gas-rich areas led to fewer mining and exploration projects,[3] consistently low well-head prices also adversely affected their commercial viability. In the meantime, gross underpricing of natural gas for the household sector resulted in excessive consumption and wastage of the fuel. These dynamics led to a burgeoning natural gas deficit in the country, which ultimately pushed the government to develop a medium-to-long-term gas import strategy. As a result, Pakistan signed two major pipeline trade agreements – the Turkmenistan-Afghanistan-Pakistan-India (TAPI) Gas Pipeline and the Iran-Pakistan (I-P) Gas Pipeline– in 2010. But these projects have been facing delays due to financing constraints and geo-political conditions in the region. To plug the gas deficit in the short term, Pakistan started importing natural gas (in liquefied form – LNG) in sizable quantities from FY15, and has since then quickly become a major buyer in the international market. At present, nearly 23 percent of the country's natural gas consumption is being met through imported

Natural Gas Supply and Consumption in Pakistan **Figure S1.2**



Source: Pakistan Energy Yearbook, HDIP (various editions)

LNG (**Figure S1.2**). The import of LNG has also helped reduce overall electricity generation cost in the country by around Rs 234 billion during FY17-20.[4]

Going forward, the natural gas shortfall in the country is projected to increase substantially, stoking the demand for further LNG imports. Although variable renewable energy (VRE) sources – such as solar and wind – provide a better alternative to achieve the least-cost energy mix and attain broader energy security over the medium-to-long-term, a number of commercial and technical constraints hamper the short-term viability of these projects. Strong political commitment, massive investment in technical capacity and planning tools, support from global development partners, and most importantly, flexibility on the part of existing

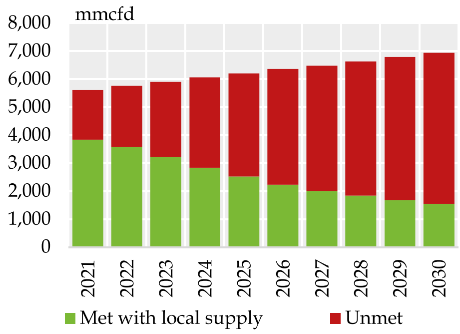
[3] "… the proven gas reserves and annual average gas production are already on a decline in Pakistan, and the oil & gas sector has failed to attract sufficient foreign investments. The energy experts identify difficult security situation, and policy delays as major obstacles to foreign investment in this sector." SBP (2015). State of Pakistan's Economy Annual Report 2014-15. Karachi: State Bank of Pakistan.
[4] During FY17-20, 72,755 GWh of electricity was generated in the country (excluding K-Electric) from LNG, at a total cost of Rs 666.3 billion. If the same quantity of electricity was generated using residual furnace oil (RFO), the total cost would have been Rs 900 billion. Data source: NEPRA (2020). *State of Industry Report 2020*. Islamabad: National Electric Power Regulatory Authority.

energy operators and investors, is required for a large-scale switch to VREs.[5] The other low-cost alternative is coal, which has gained traction lately, especially under the coal-powered projects set up under CPEC. However, burning coal to meet domestic energy requirements is not a sustainable solution, given its heavy contribution to the greenhouse gas emissions. Leading IFIs have also lately advised against developing additional coal resources in Pakistan, except for the plants already committed.[6]

Keeping these limitations in mind, it appears that the magnitude of future LNG requirements (if natural gas exploration levels and the pricing policy remain unchanged) would remain high over the short- to-medium-term. Estimates by the Ministry of Energy and OGRA suggest that Pakistan's indigenous supplies would only fulfill 22.3 percent of the estimated demand by 2030. If the long-delayed I-P and TAPI gas pipeline projects do not become operational, the average annual net gas shortfall during 2021-2030 is projected to be 2,593 mmcfd (**Figure S1.3**).[7] To put this deficit in context, it is 2.7 times the volume of LNG the country imported in 2020. Thus, it has become crucial to develop an efficient LNG market, characterized by a robust regulatory and operational infrastructure, to help run the domestic gas sector on a sustainable basis and strengthen Pakistan's energy security.

Within this context, this section intends to evaluate the existing regulatory and operational infrastructure of the LNG market (including imports and domestic sales) in the country, and discuss what is required to operate this sector efficiently and in a cost-effective manner. Since the global LNG trade is relatively new compared to oil, and is still evolving, the section initially takes stock of developments in the major markets and closely tracks the recent policy transitions in terms of nature of contracts, pricing benchmarks, and the role of governments. Similar transitions are either underway or being contemplated in Pakistan's LNG market as well.

Estimated Gas Demand in Pakistan **Figure S1.3**



Source: OGRA

Following that, the section provides a detailed account of major stakeholders in domestic LNG market, and identifies specific procedural bottlenecks causing delays at the import, transmission, and distribution stages. These challenges not only lead to recurring supply shortages, but also result in cost escalation, which ultimately feeds into

[5] World Bank (2020). *Variable Renewable Energy Integration and Planning Study*. Pakistan Sustainable Energy Series. Washington, DC: World Bank

[6] World Bank (2020).

[7] If TAPI and IP become operational, then the overall unmet demand would average 1,166 mmcfd during the same period. For unit descriptions and conversion factors used throughout the special section, please refer to **Annexure-I**.

consumer tariffs or accumulation of arrears. There is also a perception among various stakeholders in the country about the cost of imported LNG, and there are frequent debates over the quality and duration of the long-term sovereign LNG contracts and the timeliness and benefits of spot procurements. These dynamics make a strong case for greater involvement of domestic private sector in LNG import and local sales, which is expected to introduce efficient practices in LNG supply chain, as experienced by other countries in the region.

While the government has recently allowed the private sector to import LNG, and has also issued licenses to interested parties, the remaining duration of the long-term sovereign contracts implies that the private sector would be operating in parallel with the public sector for some time. But it is important to understand that private participation alone will not solve the sector's broad operational and financial problems. Specifically, without addressing the fundamental issues associated with natural gas pricing, governance in distribution companies, and uncertainties at the end of the gas supply-chain, the domestic LNG market and the overall gas sector would continue to operate sub-optimally.

In particular, while addressing bottlenecks in the existing import, regasification, and pipeline infrastructure is necessary, it is equally important to expand the LNG user-base in the country; this is especially to reduce the per unit terminal capacity charges, which the private sector would also be paying for. However, this expansion appears challenging, given the prevailing mindset of cheap/subsidized access to natural gas, which has seen users (especially industries) vying for a greater share in the indigenous natural gas pie instead of shifting to LNG. Subsidy rationalization is also important in the context of managing fiscal and quasi-fiscal costs of the government, especially when imported LNG is provided to already heavily subsidized sectors, such as households and fertilizer. The situation could become more challenging for the gas distribution companies when their high-revenue sectors (such as transport and power) start shifting their gas demand to the private sector. In this context, political consensus and strong provincial coordination is needed to get a policy buy-in for the rationalization of subsidies.

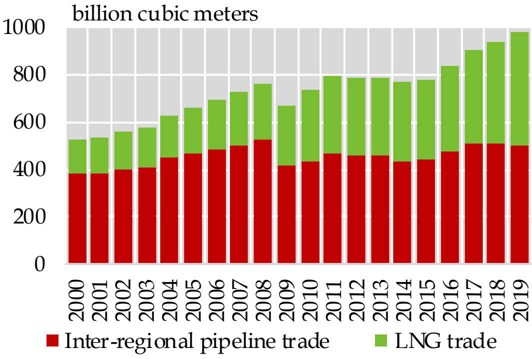
Finally, cross-sector linkages need to be carefully evaluated. In particular, the robustness of demand projections that ultimately feed into timely procurement decisions, crucially hinges on the adoption of more structured and regulatory-compliant practices in the power sector, which is consuming 60 percent of total LNG.

S1.3 Why is LNG Gaining Traction Worldwide

Natural gas was historically traded via networks of extensively laid inter- and intra-country pipelines, as its low density made it costlier to store and trade via shipping channels as compared to oil.

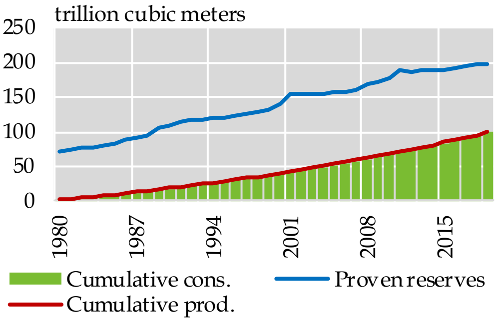
Over time, however, the industry saw rapid advancements in purification, liquefication and regasification technologies. These not only made it cost-effective to transport gas in liquefied form via specialized vessels, but also increased the commodity's trade potential by reducing the need for highly capital-intensive long-distance pipelines. As a result, this mode of transportation became increasingly popular.

Annual Trend in Natural Gas Trade **Figure S1.4**



Source: British Petroleum Statistical Review of World Energy June 2020

Global Natural Gas Proven Reserves, Cumulative Production and Consumption **Figure S1.5**



Source: British Petroleum Statistical Review of World Energy June 2020

During the last two decades (2000-2019), the volume of the global LNG trade more than trebled, with overall share of LNG in natural gas trade increasing from 27.6 percent to over 49 percent during the same period (**Figure S1.4**).

From the demand side as well, LNG has been gaining traction as a reliable source of energy, due to a number of reasons:

- First, technological advancements in power generation, particularly the advent of low-cost combined cycle generation turbine (CCGT) plants, have made it easier for oil-importing developing countries such as India, China and Turkey to switch to gas-fired power generation and take advantage of the cost flexibility.[8] This has resulted in a continuous rise in the global production and consumption of natural gas (**Figure S1.5**). Given the expected surge in Chinese and Indian economies over the medium-to-long-term, traders and energy experts are expecting a similar surge in LNG imports to cater to the growing energy needs of their industrial, residential and power sector users.

- Second, rising environmental concerns have been creating demand for cleaner fuel-sources such as LNG, since natural gas is free from sulfur, minimizes CO_2 emissions, and is more efficient in generating electricity compared to other fossil fuels.

- Third, the LNG value chain offers custom-made and small-scale solutions to cater to customers' needs; these include small liquefaction and regasification plants and bunkering solutions etc. (**Box S1.1**).

[8] CCGT power plants use both gas and steam turbines to produce electricity which is more efficient compared to traditional simple cycle plants. These power units are available in smaller sizes and involve short planning lead time.

Box S1.1: Understanding the LNG Value Chain

In contrast to the pipeline trade of natural gas, LNG trade requires substantial investments at multiple stages of value addition. The first stage in converting natural gas to LNG is the exploration of natural gas from underneath the earth's surface. Countries with an exportable surplus of natural gas reserves export the commodity; exploration contributes approximately 11 percent to the overall cost of LNG. The next step is liquefaction, which involves the removal of various extraneous elements and ensures consistent composition and combustion characteristics of the natural gas.[9] The liquefaction process requires huge investments and adds 42 percent to the overall LNG cost. Once natural gas is converted to liquid form (i.e., LNG), it is transported to the importing countries via specialized trucks and ships; for long distances, shipping is the preferred option. The overall transportation/shipping approximately adds 20 percent to the LNG cost borne by the importer. In the next stage of the value chain, the marine terminals at the importing destinations receive the LNG, store it, and later convert it back into gaseous form. In some countries, ships and barges – such as Floating Storage Units (FSUs), Floating Regasification Units (FRUs), and Floating Storage and Regasification Units (FSRUs) – perform these different functions. These floating facilities provide a rapid and low capital cost solution to the LNG importing countries, and approximately sum to 27 percent of the overall LNG landed price. In the last stage, the LNG in gaseous form is transported to the final customers through the countries' own transmission and distribution networks.

Reference:

GIIGNL (2019). *The LNG Process Chain*. LNG Information Paper#2, October 2019 update. France: International Group of Liquefied Natural Gas Importers

As a result, the number of players in the global LNG supply chain rose manifold since the turn of the century. On the export front, new players such as Qatar, Australia, and recently the US, emerged and eventually surpassed traditional exporters such as Indonesia, Malaysia and Russia. Meanwhile on the imports front, China, India, and Pakistan generated sizable LNG demand in the international market. In response to mounting needs, the global LNG infrastructure underwent significant capacity expansions. From exploration to liquefaction, and shipping to regasification and distribution, all activities have seen a noticeable surge in investments.

For instance, the discovery of sizable shale gas reserves in the US had a market-altering impact on the global LNG trade, as the country transitioned from a net-importer to a net-exporter within the span of just a few years by investing heavily in export infrastructure. In the face of growing competition, Qatar has also recently planned to increase its LNG production-handling capacity by 64 percent by 2024, to make use of its recently discovered gas reserves. Similar expansion plans have also been announced by other natural gas producing countries, including Canada, Mozambique and other West African countries.[10]

Likewise, importing countries have been investing heavily to increase their LNG regasification, storage and pipeline

[9] In this process, refrigeration technology is used to cool, condense and liquefy the natural gas so it can be converted to liquid form at a temperature of approximately -162ºC. At standard temperature of 15.6ºC, LNG occupies around 600 times lesser volume than natural gas, which makes LNG trade a feasible and economically viable option even for remote and distant locations.

[10] Source: International Energy Agency.

capacities. For example, India, Bangladesh, China, and Brazil, activated new LNG regasification terminals in 2019. Meanwhile, new players are also embracing LNG imports; Philippines, El Salvador, Ghana, Cyprus, Croatia and Vietnam are in the process of setting up their first receiving terminals.

Recent Policy Transitions

An increasing shift to market-based LNG business

Initially, the governments or designated state regulatory bodies in both the exporting and importing countries were solely responsible for drafting the LNG trade agreements, and for building and maintaining the distribution and transmission infrastructure. In order to mitigate commercial risks, the contracts were drafted on a long-term basis, with fixed prices, pre-committed volumes based on a take-or-pay basis[11], and government guarantees. In such a model, exporters bore risks on the pricing front by locking in rates that, depending upon international dynamics, may end up being consistently lower than the prevailing spot prices. On the other hand, the buyers/importers accepted the risk on the volume front and, thus, had to ensure the development and operationalization of necessary infrastructure, and generation of enough demand to cater to the provisions made under the take-or-pay obligations. The importers under long-term contracts also assumed the risk of lower spot prices than the rates locked-in under their agreements.

With regards to regasification, transmission and distribution, the government of the importing country would often sign contracts with international oil companies (IOCs) and multilateral agencies to set up regasification units (both onshore or offshore), which were run by public sector enterprises.

However, after the installation and operationalization of the basic terminal and pipeline infrastructure by the governments of the LNG importing countries, there has been a growing trend toward deregulation and liberalization of the downstream LNG business in the wake of growing LNG demand. Japan and South Korea are major examples in this regard (**Box S1.2**). Their experience reveals that greater private sector involvement leads to better price discovery, based on the underlying market dynamics.[12] Furthermore, it results in greater operational efficiency, as private players strive to grow in the absence of government-backed guarantees and notified or supported prices.[13]

Multiple Pricing Options Have Emerged

In the relatively new LNG markets, the traders experience challenges with price discovery and unavailability of appropriate benchmarks. Furthermore, as mentioned above, most international contracts were state-executed, with governments treating important articles regarding pricing

[11] In the take-or-pay clause, the buyer is obliged to pay for a specific minimum annual quantity of gas at the contract price, irrespective of the volume of gas it actually receives.
[12] Source: IEA (2019), *LNG Market Trends and Their Implications*, IEA, Paris.
[13] Colombo, S., El Harrak, M., & Sartori, N. (2016). *The Future of Natural Gas: Markets and Geopolitics*. Hof van Twente: European Energy Review.

arrangements, ascribed volumes, and terms of pay-or-take provisions as highly confidential. Such complexities made the overall LNG pricing structure obscure and complex.[14]

For instance, in Asia, due to the absence of a regional liquid trade market in the beginning, LNG prices were predominantly linked to crude oil under government-to-government agreements. However, as the market matured and the participation of private players increased, multiple alternative pricing options emerged (**Table S1.1**). For example, traders have started to use Gas-on-Gas prices, especially in big importing countries such as Japan and South Korea; China and India have also been increasingly transitioning towards market-based prices. This change materialized after the initiation of short and spot LNG trade between Asian and Atlantic economies, specifically after 2005.

Box S1.2: Liberalization in the Gas Market – The Case of Japan

In Asia, the three largest LNG importers - Japan, Korea and China - have all implemented multiple reforms in their domestic gas markets to deregulate retailing, increase competition and lower the cost of LNG.

Japan, for instance, had started the deregulation process in 1995, and had fully liberalized its retail market by 2017. Being the largest importer of natural gas and LNG, Japan meets around a quarter of its energy demand through LNG imports from Australia, USA, Qatar and Russia. The main consumers of natural gas in Japan are power supply companies and city gas, which distribute the fuel among industrial, commercial, and household sectors. Before the reform process in 1995, high fixed costs and economies of scale were the main reasons for the monopolistic nature of the retail gas market, with the government supporting the structure through tariff regulations and supply and safety obligations.

However, due to the growing demand from large-scale industrial users, the government introduced the first round of reforms in 1995, followed by subsequent rounds in 1999, 2004, 2007 and 2017. Under the reform process, the government had allowed non-traditional gas companies to sell gas in any area. Under the Gas Business Act 2015, the Japanese government abolished the regional monopoly in the retail market and allowed registered companies to enter the retail market. It also lifted the tariff regulations that were previously imposed on the retail companies. In addition, the government introduced a licensing system, where the companies were required to have licenses for gas manufacturing, pipeline service and gas retail business.

Furthermore, to encourage third parties' access to LNG terminals, the terminal owners are prohibited to reject third-party use, and are required to report and publish their annual utilization plans. Besides, the government also introduced the legal unbundling of the pipelines' service business and allowed new entrants to use the pipeline networks. This act necessitated the legal separation of the pipeline service business from the major gas companies by 2022, with the overall objective to promote retail competition in the pipeline network, as well as the import and terminal networks.

[14] Source: Ason, A. (2019). *Price Reviews and Arbitrations in Asian LNG Markets*. OIES Paper NG 144. Oxford: The Oxford Institute for Energy Studies.

Reference:

IEA (2019). *LNG Market Trends and their Implications: Structures, Drivers and Development of Major Asian Importers*. France: International Energy Agency.

This is because such pricing had already been popular in the North American and European markets, including in Russia. In North America, for instance, the Gas on Gas (GOG) prices represented 100 percent volume of the natural gas market (this mainly represented pipeline gas contracts), whereas in other regions, like the former Soviet Union, a large number of natural gas contracts are based on the Regulation cost of services (RCS) and the Regulation below cost (RBC) models (**Figure S1.6**).[15] As the Asian market developed, region-specific benchmarks also started gaining traction. These include the Japan-Korea Marker (also called the Asian spot index), and the newly-launched West India Marker (WIM).

The emergence of LNG portfolio players and spot market

In the LNG market, sellers seek long-term contracts to safeguard the interest of their investments, while buyers prefer short-term

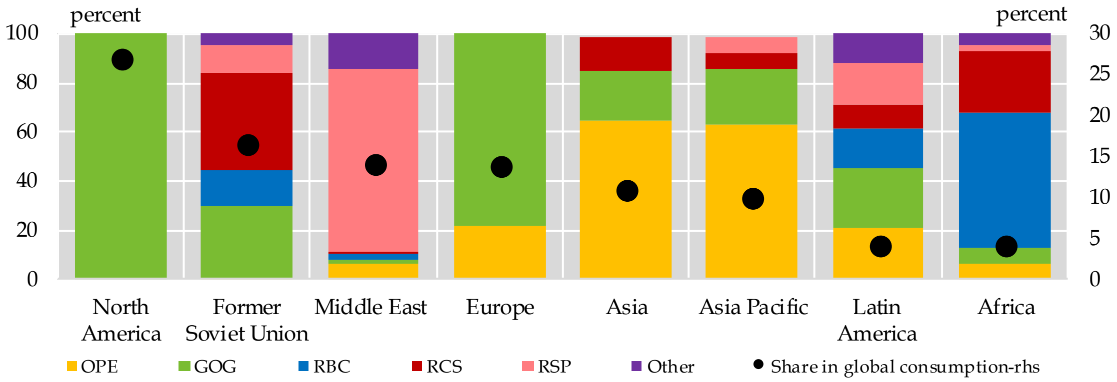
Types of Wholesale Natural Gas Pricing Formation Mechanisms **Table S1.1**

Mechanism	Description	Followed by
Oil price escalation (OPE)	The price is linked, usually through a base price and an escalation clause, with competing fuels, typically crude oil, gas oil and/or fuel oil. In some cases, coal or electricity prices can also be used.	China; Japan; S. Korea
Gas-on-gas competition (GOG)	The price is determined by the interplay of supply and demand – gas-on-gas competition – and is traded over a variety of different periods (daily, monthly, annually or other periods). Trading takes place at physical hubs (e.g., Henry Hub) or notional hubs (e.g., the National Balancing Point in the UK).	Russia; Europe; Colombia
Bilateral monopoly (BIM)	The price is determined by bilateral discussions and the agreements are reached between a large seller and a large buyer, with the price being fixed for a period of time – typically one year. There may be a written contract in place, but often the arrangement is at the government or state-owned company level.	Qatar; UAE; Iraq
Netback from final product	The price received by the gas supplier is a function of the price received by the buyer for the final product the buyer produces. This may occur where the gas is used as a feedstock in chemical plants, and is the major variable cost in producing the product.	Trinidad & Tobago
Regulation: cost of service (RCS)	The price is determined, or approved, formally by a regulatory authority, or possibly a ministry, but the level is set to cover the "cost of service", including the recovery of investment and a reasonable rate of return.	China; Bangladesh; Malaysia
Regulation: social and political (RSP)	The price is set, on an irregular basis, likely by a ministry, on a political/social basis, in response to the need to cover increasing costs, or possibly as a revenue raising exercise – a hybrid between RCS and RBC.	Iran; Saudi Arabia; Oman
Regulation: below cost (RBC)	The price is knowingly set below the average cost of producing and transporting the gas, often as a form of state subsidy to the population.	Egypt; Algeria; Former Soviet Countries

Source: IGU (2020). Wholesale Price Survey 2020. Barcelona: International Gas Union.

[15] Hub-based price indices include the US' Henry Hub and the UK's National Balancing Point (NBP).

Composition of Price Structure in LNG Market **Figure S1.6**

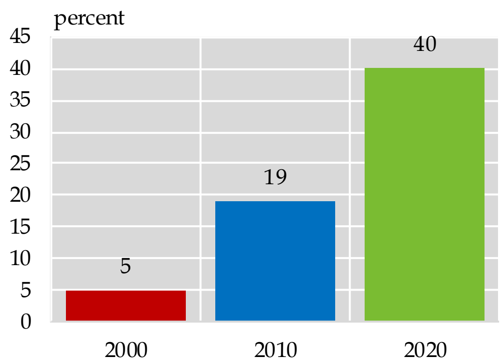


Source: IGU (2020). *Wholesale Price Survey 2020.* Barcelona: International Gas Union

contracts to diversify supplies and avoid -volume commitments. Because of this, the role of portfolio players has become increasingly important in recent years. These players hold a portfolio of LNG supply, shipping, storage and regasification assets in different regions, and are therefore able to offer more flexible buying and selling options to exporters and importers. Portfolio players have become increasingly involved in the short-term and spot sales, and handle large volumes of "flexible gas supplies" (i.e. non-contracted and free to be supplied anywhere) purchased primarily from the US and Australia.[16]

In the spot market, the excess and uncommitted LNG volumes are sold in other than contracted markets on the basis of single transaction sales. This trend gained significant momentum in the 2010s with a sudden rise in demand from East Asia following the shutdown of nuclear power plants in Japan and lower demand in the European region.[17] As a result, the share of spot and short-term trade in global LNG trade has increased rapidly between 2000 and 2020 (**Figure S1.7**)

Share of Short-term and Spot Purchases in Total LNG trade **Figure S1.7**



Source: International group of Liquified Gas Importers (GIIGNL)

S1.4 The current state of LNG market in Pakistan

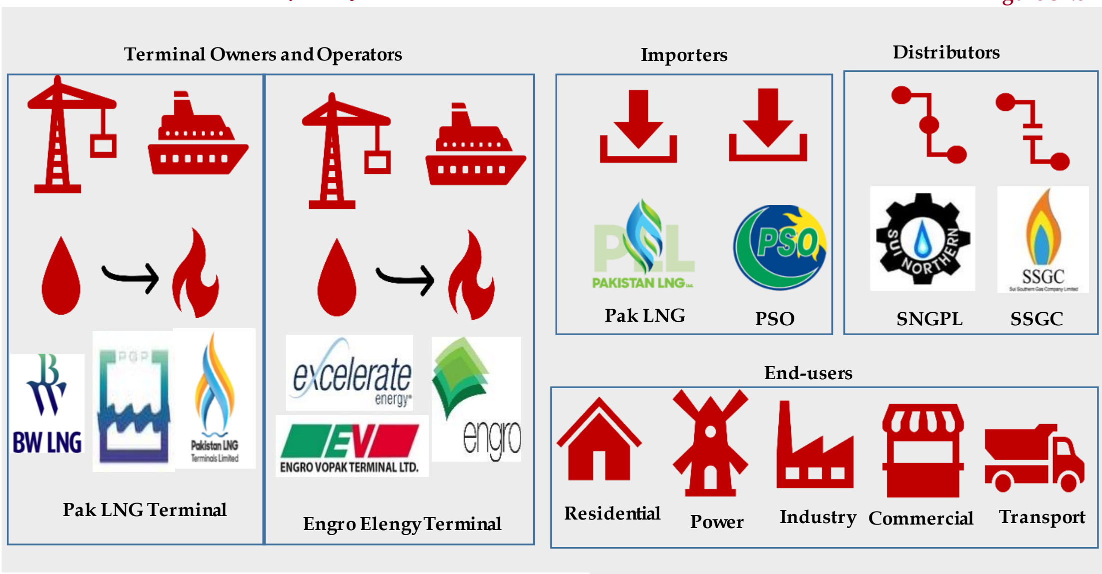
Physical infrastructure

As in most other countries transitioning towards LNG, the associated trading and distribution infrastructure is still at a

[16] Source: GIIGNL (2020)
[17] Source: IEA (2020), 'LNG Market Trends and Their Implications'

LNG Sector in Pakistan – Major Players

Figure S1.8



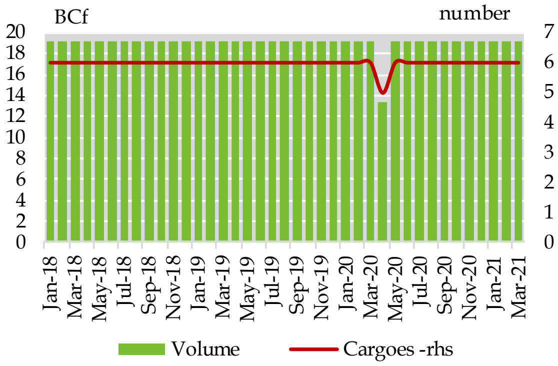
Source: Company reports and official websites

developing stage in Pakistan. The country started imports only in 2015 to bridge the rising demand-supply gap. Encouragingly, in a short span of five years, the sector has established strong footings and a basic supply chain structure.

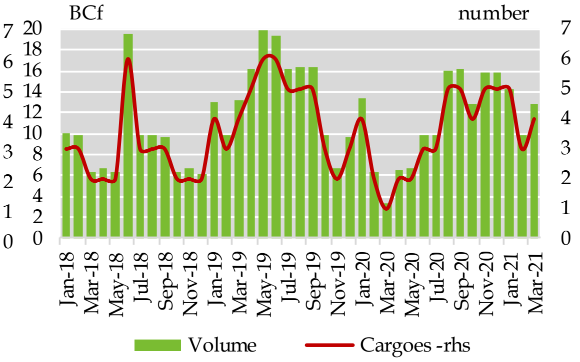
The current LNG value chain comprises two Floating Storage and Regasification Units (FSRUs) with different import-handling facilities at Port Qasim Karachi. The first terminal – Engro Elengy Terminal (Private) Limited (EETL) – commenced operations in 2015, and currently provides handling and regasification facilities to Pakistan State Oil, which has the mandate to import the contracted supplies under the long-term agreements. The second terminal, – Pakistan LNG Terminals Limited (PLTL) – was built in 2017 by Pakistan GasPort Consortium (PGPC), and currently provides handling and regasification facilities to another state-owned importer, Pakistan LNG Limited (PLL). The existing pipeline network of the two public Sui gas companies is utilized to transport and distribute imported LNG from the terminals to other parts of the country (**Figure S1.8**).

At present, the two FSRUs have a government-contracted capacity – on a take-or-pay basis – of around 600 mmcfd each. The installed regasification capacity of the two units stands at 690 mmcfd and 750 mmcfd, respectively. As shown in **Figure S1.9**, on average, 6 LNG cargoes are coming every month at Engro Elengy, with quantities amounting to 19 million mmbtu, roughly at par with the contracted capacity of the

Monthly Imports by PSO **Figure S1.9a**



Monthly Imports by PLL **Figure S1.9b**



Source: OGRA, Pak LNG, and Engro

terminal.[18] In the case of PLL, however, the average capacity utilization since its operationalization has averaged 65 percent, with 3-4 cargoes berthing every month.

Presently, Pakistan has been importing LNG under a government-to-government LNG agreement (15-year contract with Qatar on take-or-pay basis) as well as four agreements with private suppliers in Italy and Qatar (also term contracts on take-or-pay basis). During the last 3 years, more than 87 percent of the imported LNG in Pakistan came under these term agreements. The remaining 13 percent comprised spot purchases, to cater to demand in excess of the term contracts. Under the existing arrangement, the EETL terminal receives all the contracted volumes imported by PSO, whereas the PLL receives both long-term and spot cargoes.

Regulatory and operational framework

The upstream and downstream natural gas sector, including the import of LNG, is being regulated by a comprehensive legal framework, which comprises policies, rules and regulations that are enforced by different ministries and regulatory bodies. The government has authorized OGRA to manage LNG allocation, pricing, and other associated matters.[19] OGRA issues licenses to design, construct and operate the LNG terminals and the pipeline infrastructure, and also computes and notifies the weighted average cost of imported LNG for domestic users.

The operators of LNG terminals are also required to secure NOCs from relevant authorities, including the Ministry of Energy (Petroleum Ministry), Port Qasim Authority, Ministry of Maritime Affairs, Defense Ministry, Ministry of Industries and Production, Civil Aviation Authority, Sindh Environmental Protection Agency, Naval Headquarters/Maritime Security, Sindh

[18] With a utilization rate of 98 percent, the terminal was the fastest in the world to achieve 250 ship-to-ship LNG transfers. Source: company press release [https://www.engro.com/press-releases/u-s-ambassador-commends-engro-elengy-on-worlds-fastest-250-ship-to-ship-transfers/]
[19] Source: OGRA

Govt. District Administration and the City District Government, Karachi.

The Ministry of Energy (Petroleum Division) is solely responsible for issuing sector-specific policies, such as the LNG Policy (2011), Third Party Access Rules (TPA),[20] and the Natural Gas Allocation and Management Policy. In addition, the ministry reviews and executes the gas price agreements between the producers and the government-nominated buyers; and it also ensures the safety of natural gas pipelines, in coordination with the law enforcement agencies.[21]

Currently, the government is the sole player in the LNG-importing business. This is in line with the global practice of heavy state presence during the initial stages of the LNG market development, to build the basic infrastructure, implement policies governing the fuel-mix, and generate local demand from industries, power and transport sectors. The LNG procurement process typically starts with the estimation of LNG demand, which originates from end-consumers like the power sector (including captive power plants), general industries, transport, and households. In particular, the Sui companies are mainly responsible for forecasting future demand of gas by different consumer segments. The Sui companies present their projections to the Petroleum Division, which weighs the projected demand against the contracted supplies from long-term arrangements, and then submits a formal request to PLL to procure additional volumes from the spot market, if needed. PLL then floats the tender in the international market, and procures the required quantities.

S1.5 Challenges arising out of Present Operational and Administrative Structure

The domestic natural gas market has consistently been prone to various challenges, such as supply shortages during winter seasons, difficulties in timely delivery of adequate quantities to the power, industrial and residential sectors, and the financial constraints faced by the distribution companies while ensuring implementation of OGRA-notified sector-wise gas tariffs. With substantial government involvement across the LNG supply chain and a distorted subsidy structure, price discovery in the natural gas sector becomes harder. Besides, a common perception that seems to prevail is that the prevailing price of LNG in Pakistan is on the higher side, and that this has more to do with the take-or-pay nature of the contracts (regards to both the capacity charges of the terminals and the fuel's import cost), than with the trends and levels of global prices. Furthermore, governance issues, procurement timings, global bargaining position, and financial considerations of the distribution companies, are also believed to contribute to the escalation in the LNG import cost.

While there might be merit in some of these arguments, our analysis suggests that these kinds of problems (especially contractual issues and procurement timings) are not unique to Pakistan. As mentioned before, the global LNG market does not have a long history; it is still evolving and is in the

[20] Under TPAs, third party importers and marketers of LNG are allowed to utilize any excess gas capacity available with the Sui gas distribution pipeline companies (SNGPL and SSGC) on a short-term basis.
[21] Ministry of Energy (Petroleum Division)

process of embracing changes on policy and procedural grounds. Pakistan's LNG market would experience a similar transition (e.g., changes in term-spot balance, nature of additional import/ terminal contracts, and modifications in public procurement rules) in due course. Furthermore, as will be discussed later in this section, the current operational and procedural challenges have more to do with heavy (rather, exclusive) involvement of the public sector in the business. These issues are expected to be addressed to a large extent with the private sector's participation in the LNG import and marketing business going forward.

The following points present the major challenges that arise out of the existing operational and administrative structure of LNG imports in Pakistan.

The uncertain demand from the power sector

Demand projection is a critical element in the LNG procurement business, as the spot purchase decisions are based on the import requirements communicated by the end-users to the importers. In case of Pakistan, this issue gets complicated due to a narrow user base and uncertainties associated with the power sector's consumption - as the sector takes up more than half of the imported LNG. Specifically, LNG-based power plants in the country are known to be highly efficient and are ranked above the oil-based plants in the merit order. However, recurring transmission bottlenecks compromise the merit order, and these power plants are sometimes forced to operate below capacity. This uncertainty related to the level of their capacity utilization makes it challenging for these plants to accurately assess and subsequently communicate their actual monthly fuel requirements to the Sui companies.

Procedural delays

Once the import request is placed by the Petroleum Division, PLL initiates the process of placing the tender. As a public owned entity, PLL has to fulfill all the requirements under the Public Procurement Regulatory Authority (PPRA) regulations. Though the guidelines ensure transparency in the public procurement process, the length and duration of the required procedures delay shipment arrivals. In light of the PPRA rules, the overall import procedure takes up, on average, more than 60 days, with a 30-day mandatory period between advertisement and bid submission and a 10-day period between bid announcement and award of tender (**Box S1.3**).

Apart from creating a timing mismatch from when the commodity is needed and when it is actually supplied, this lead time may also be unfavorable from the pricing perspective, as the PLL effectively locks in the import price 40 days in advance. Since the spot LNG market exhibits more volatility as compared to other fuels, prices can move substantially in either direction by the time the LNG vessel arrives. This uncertainty may then be implicitly factored in the form of higher rates quoted by the exporting companies that submit the spot bids to PLL.

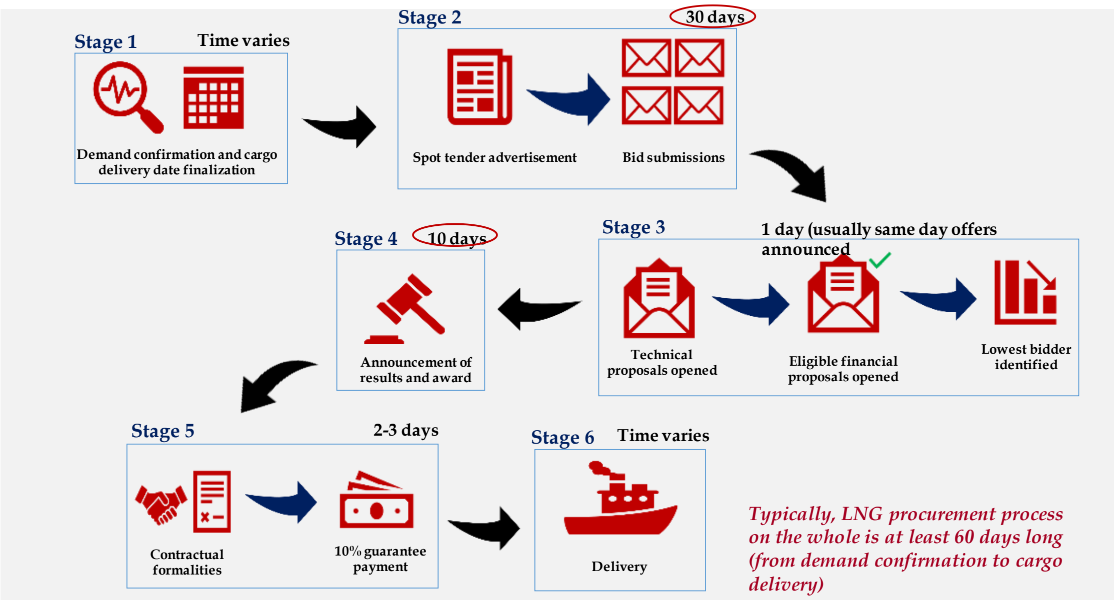
Box S1.3: LNG Procurement Process in Pakistan - A Brief Description with Timelines

Stage 1: After taking into account LNG demand and constraints (terminal, pipeline, port-related etc.), delivery dates of the LNG cargoes are locked.

Stage 2: Based on the locked delivery dates/windows, a tender is advertised. The tendering/procurement process is in accordance with the Public Procurement Regulatory Authority (PPRA) Rules. Once the delivery dates are locked and a tender is advertised, any change in demand will necessitate restarting the procurement process. If the procurement process is not restarted, the required amendments may lead to either a shortage of gas and/or penalties on account of delay in cargo discharging. According to PPRA Rules, there must be at least 30 days between the advertisement and the bid submission dates (**Figure S1.3.1**).

Stage 3: Bids received are opened the same day (first technical and then financial, based on the single-stage two envelope procedure), and the offers are announced (and the lowest bidder identified) after the technical evaluation of the bids.

LNG Procurement Process in Pakistan - A Brief Description with Timelines **Figure S1.3.1**



Stage 4: As per PPRA Rules, at least 10 days must be provided between the announcement of offers and the award of the tender.

Stage 5: Contractual formalities are completed and successful bidder furnishes a performance guarantee. According to PPRA rules, the amount shall not exceed 10 percent of the contract amount.

Stage 6: The LNG cargo is delivered on the locked delivery date/window. Weather, operational and technical reasons may lead to amending the schedule, based on mutual consent as per the provisions of the contract.

From the policy and operational perspective, it will be prudent to provide sufficient time between Stages 5 and 6. This time will allow the LNG vessel to reach Pakistan. For perspective, an LNG cargo takes around 3 days from Qatar and around 35 days from the US to reach Pakistan. Considering the mandatory

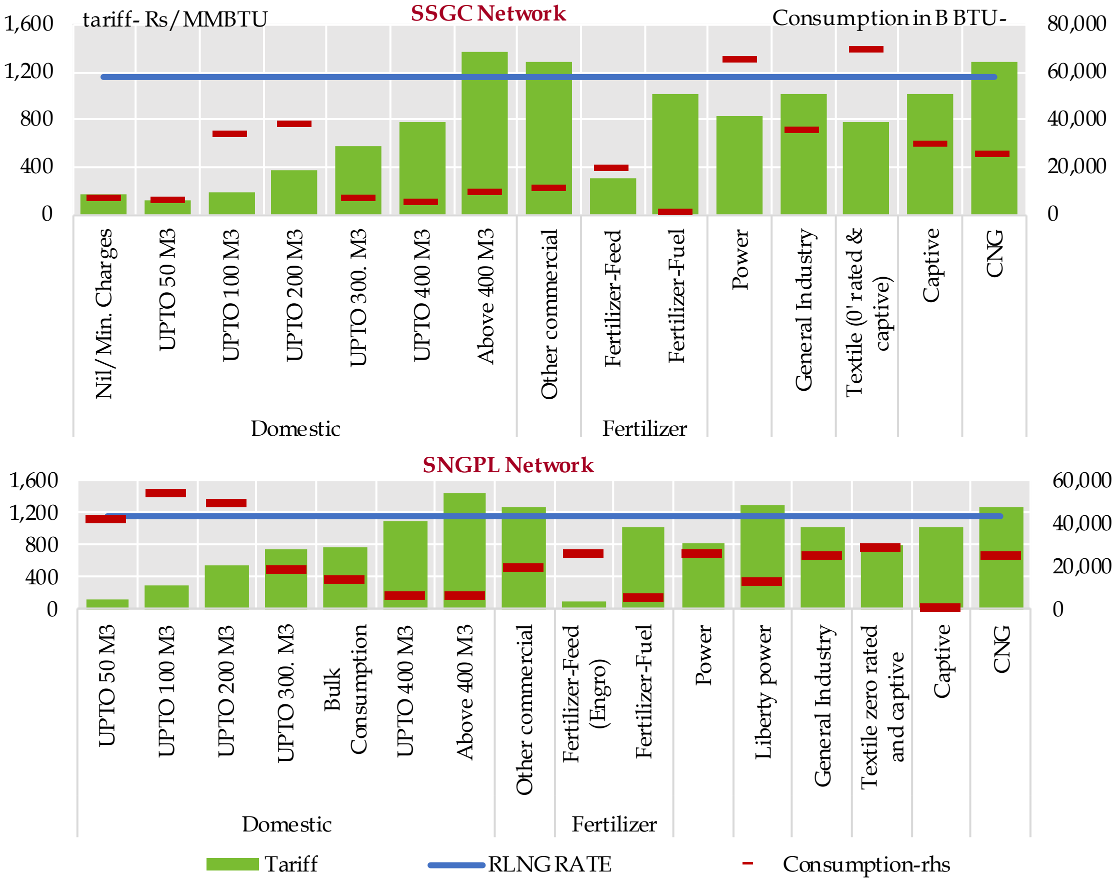
PPRA timelines requirement and the time required for the LNG vessel's voyage, the LNG procurement typically takes at least 60 days (from demand confirmation to cargo delivery).

Reference:
PPRA Rules, Public Procurement Regulatory Authority; input from procurement agencies.

Gas pricing structure and excess capacities

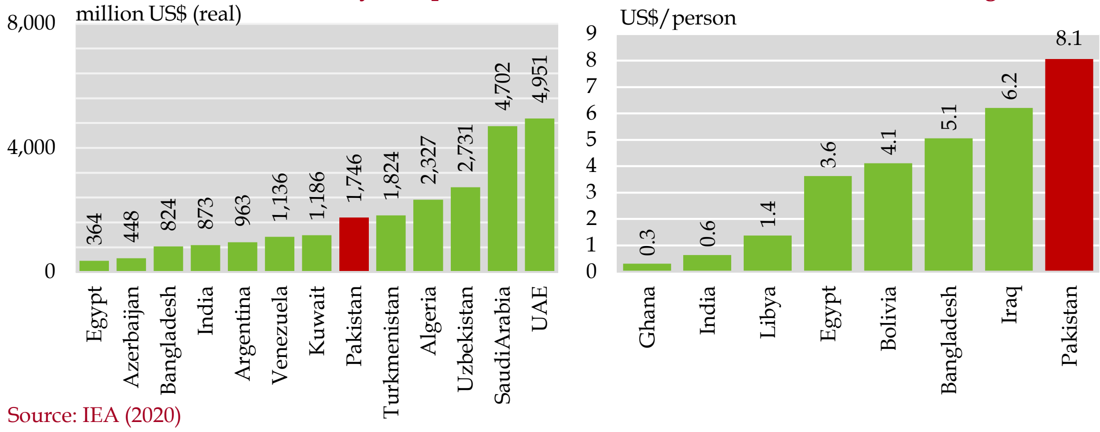
Presently, the pricing of natural gas in the country is premised on the provision of cross-subsidies: the household sector (also termed as domestic or residential sector) and fertilizer sector (for feedstock) are subsidized heavily, at the cost of commercial and transport sectors (**Figure S1.10**). According to the International Energy Agency, Pakistan featured in the top 10 countries providing the most subsidies to the natural gas sector in 2019, with the level close to the one observed in the gas-exporting countries. The amount of the subsidy was around US$ 1,750 million in real terms, or US$ 8.1 per person in Pakistan. For reference, the gas subsidies in India and Bangladesh were US$ 873 million (US$ 0.6 per person) and US$ 824 million (US$ 5.1 per person), respectively (**Figure S1.11**).

Gas Tariffs and Consumption of Natural Gas in Different Sectors **Figure S1.10**



Source: OGRA, Tariff Petitions for SSGC(16th Oct 2019), SNGPL(15th Oct 2019)

Gas subsidies - A Cross-country Comparison **Figure S1.11**



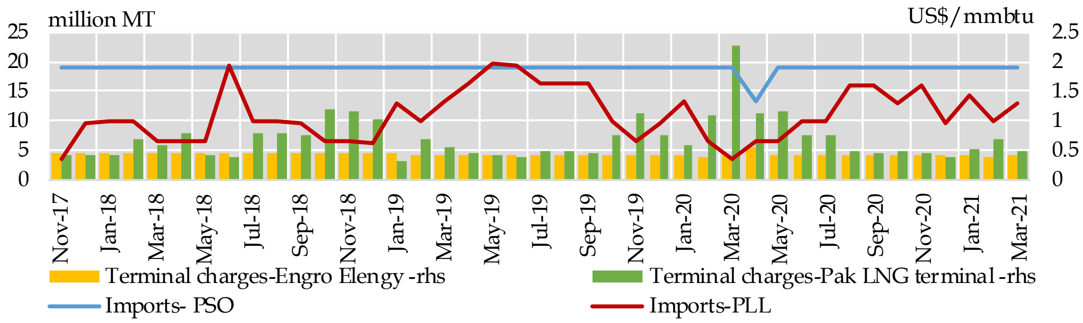
Source: IEA (2020)

Meanwhile, the LNG price is notified by OGRA on a weighted average basis, after taking into account various factors - such as the import volumes, delivered ex-ship (DES) price,[22] importer margins, terminal charges, retainage and T&D loss adjustments, cost of supplies to pipeline companies, and the margins of the distributors (see **Annexure-II** for details). The end result is that the imported LNG becomes significantly more expensive than the indigenous natural gas, especially for households, fertilizers (for feedstock) and general industries. The share of these sectors in total gas consumption is around 70 percent, which basically implies that the bulk of gas users would resist shifting to LNG at the prevailing prices. The demand will only be generated in these sectors when indigenous natural gas is not available. In the absence of demand from these sectors, it becomes difficult to utilize the terminal capacities of the FSRUs completely. This, in turn, leads to higher terminal charges per unit of gas sold (**Figure S1.12**), and the price-demand spiral ultimately feeds into even higher LNG prices and further suppression of demand.[23]

[22] The delivered ex-ship price (DES) is calculated by applying the agreed-upon Brent slope under the term or spot contracts on the average of the crude spot prices of the last three months. The resulting US$/mmbtu prices of each cargo would then be used to to a weighted average DES price for the two importers, PSO and PLL (based on quantity of imported LNG).

[23] "Under the LNG import tolling commercial structure, the user or users of the LNG import terminal are different entities than the owner of the LNG import terminal. The LNG terminal company need not buy LNG or sell natural gas, but rather provides regasification services (without taking title to the natural gas or LNG) under one or more long-term terminal use agreements. The LNG terminal company revenues are derived from tariff payments paid to the LNG terminal company by the terminal users. The payments typically take the form of a two-part tariff: (1) fixed monthly payments cover the LNG terminal company's debt service, return of and on equity, and fixed operation and maintenance costs, and (2) variable regasification service payments are designed to cover the terminal company's variable operation, maintenance and other costs, such as the terminal's power costs". Reference: DOE (2017). *Understanding Natural Gas and LNG Options*. Washington, DC: US Department of Energy.

Individual Terminal Tolling Charges **Figure S1.12**



Note: Under the tolling structure, the import terminal owner provides and charges a fee for services such as offloading, storage, and regasification from the importers (in this case, PSO and PLL). These tariffs depend on the level of terminal capacity utilization, with the rates increasing if there is any unutilized capacity.
Source: OGRA

Arrear accumulation with the distribution companies

The slab-wise pricing is resulting in substantial accumulation of arrears with the Sui companies. This is because sectors with access to subsidized rates, particularly the lower slabs of the residential sector and the feedstock slab of the fertilizer sector, are consuming substantially more gas than the ones paying above-average rates. With the cross-subsidy mechanism not working as intended, substantial arrears for the two gas distributing companies are being generated, and these are resulting in a rapidly growing circular debt in the gas sector.

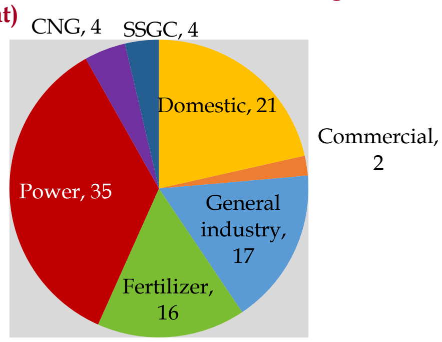
The result is visible if we compare the sector-wise gas consumption with the sector-wise revenues of the Sui companies. For example, while the fertilizer feedstock sector consumes 16 percent of natural gas, it contributes just 3 percent to the revenues of the distribution companies. Likewise, the household sector consumes 21 percent of the natural gas, but contributes only 11 percent to the gas companies' revenues (**Figure S1.13**).

S1.6 The ongoing onboarding of private sector and capacity expansions

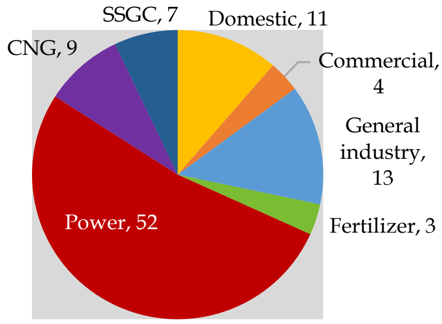
The analysis presented in the previous section reveals that heavy public sector involvement in all the stages of the supply chain – from assessing demand to imports and pricing – is one of the major reasons for the import delays, price distortions and distribution lags in the domestic LNG market. In order to avoid these problems in the future, Pakistan should learn from other LNG-importing countries in the region, and allow as well as incentivize increased involvement of private sector in the LNG supply chain. This would be in line with the experience of both the more mature LNG markets, such as Japan and South Korea, and some emerging ones, like India. Higher private sector involvement in these countries helped accelerate the adoption of the cheaper fuel across the economy, and smoothen supply chain dynamics by streamlining procurement processes and enabling market-based price discovery.

Encouragingly, in Pakistan, the government has recently started allowing private sector importers to utilize the excess capacities of

Share in Natural Gas Consumption (percent) **Figure S1.13a**



Share in Revenue (percent) **Figure S1.13b**



Note: 'These are consolidated figures for both SNGPL and SSGC. The "SSGC' slice in both the charts represents the amount of LNG withheld by SSGC.
Source: Pakistan Energy Yearbook 2019; HDIP; Financial Statements of SNGPL and SSGC; OGRA

the existing terminals. The willing players can enter the market in the following way:

- First, they would need a license for sale of natural gas/LNG from OGRA. At present, Trafigura Pakistan, Energas, and Tabeer Energy have been granted licenses.
- After that, the private sector players can approach the terminals via a Third Party Access (TPA) arrangement, which would allow them to participate in an auction to secure access to the unutilized capacity.

However, the process of auctioning the unused capacities is complex due to a couple of reasons. First, given that demand fluctuations are common and that the forecast system is not up to par, the private players would remain uncertain of having access to terminal capacity commensurate with the amount booked under short- to medium-term orders by the end-users. Second, as there are no finalized procedures to oversee the auctioning process (the TPA regulations are in draft form and function as a guiding document), the whole procedure involves all the supply chain players getting into a new FSRU-pipeline usage agreement/ understanding each time the government authorizes auctioning of the excess capacities. Note that this adds to the already lengthy procurement process of around 60 days of securing spot purchase deliveries.

Given these operational limitations with the existing terminals, and realizing that the expected demand would remain unmet even after the private sector fully utilizes the excess capacity, the government has started expanding the existing terminals. In addition, the construction of three new terminals (one on-shore and two FSRUs) has also received regulatory approvals. According to OGRA's estimates, the country needs the terminal send-out capacity to increase by around 150 percent by FY30, to handle the additional demand of 1,998 mmcfd of LNG; the planned capacity expansions are expected to plug this balance.

Specifically, Excelerate Energy and Engro Elengy have signed a Heads of Agreement (HOA), under which Excelerate will exchange its existing FSRU Exquisite with a new-build FSRU. This would increase the send-out capacity by around 150 mmcfd, and the excess capacity would be available to the private sector via TPA arrangements.[24] Meanwhile, the firm is also working to construct a separate on-shore LNG terminal, PakOnshore LNG, with a projected send-out capacity of 1,200 mmcfd.[25] The PLL is also expanding its capacity by around 150 mmcfd to accommodate orders from K-Electric going forward. Furthermore, the two private companies, Energas and Tabeer, have been granted licenses by OGRA to set up their own terminals. The two FSRUs would have a combined send-out capacity of 1,550 mmcfd. All these expansions are expected to increase the country's total send-out capacity by 2,900 mmcfd within the next three to four years.

The eventual increase in capacities, especially onshore, means that terminal operators would also be able to store the imported LNG. Storage of gas is vital to: (i) balance the sectoral demand fluctuations due to seasonality; (ii) ensure that the country has supplies available in case of a major disruption in the international supply chain or a sudden increase in regional/global gas prices; and (iii) take advantage of lower prices to lock in supplies for future use. However, given that LNG storage is costly, there would be a need to make more accurate demand forecasts and improve communication and coordination between the government authorities, importers and terminal operators, to ensure timely deliveries of the required amounts of LNG. Furthermore, terminal send-out capacity of expanded and new terminals would need to be backed up by a commensurate increase in the distribution pipeline network to ensure their business viability.

In particular, the limited pipeline capacity means that there is a lot of uncertainty in terms of their ability to meet the committed future demand. Because of this, planned expansions in terminal capacities would not become operational unless there is sufficient capacity available in the pipeline network (and vice versa).

At present, while the two Sui gas distribution companies have been investing to enhance the pipeline network keeping in view the future demand, the existing pipeline network is still insufficient to cater to the additional demand. In particular, these companies can transport around 1,800 mmcfd of natural gas across the country, with a great amount of monthly volatility during the year. During FY20, for example, around 798 mmcfd of LNG was sold on average via the pipeline network, with the amount reaching as high as 1,270 mmcfd during July and as low as 502 mmcfd during February.

Even in periods with low distribution, it becomes challenging for the Sui companies to accommodate the demand from users/importers with whom they have not signed any Gas Transportation Agreement (GTA). This is because, under the OGRA Third Party Access Rules 2018, any unutilized or excess pipeline capacity is offered to private parties on a three-month forward and first-come-first-serve basis, after approval from all the relevant stakeholders. In this regard, uncertainties in the demand from the private sector and the possibility of any unplanned surge in send-out from the public sector, may discourage both the Sui companies and the private sector from

[24] Source: Company press release (https://www.engro.com/press-releases/excelerate-energy-and-engro-elengy-terminal-agree-to-expand-pakistan-lng-import-terminal/)
[25] Source: Company press release (https://www.engro.com/press-releases/pakistan-onshore-lng-invite-expressions-of-interest-to-setup-pakistans-first-onshore-lng-terminal/)

booking the capacity usage three months in advance.

To this end, substantial investments are required to: (i) increase the distribution capacity to supply more gas to users already connected to the gas pipeline network, while expanding the pipeline network to reach off-grid users; and (ii) in the interim period, utilize alternative ways to supply excess LNG to the end-users.

With regards to the first option, the Pakistan-Russia joint project on the Pakistan Stream Gas Pipeline is under consideration. The 1,100 km pipeline would have the capacity to transport around 1,600 mmcfd of LNG. For the second option, two private sector companies - LNG Easy Pakistan and Daewoo Gas - have recently been granted provisional licenses by OGRA to establish virtual pipelines to distribute LNG via cryogenic bowsers.[26] LNG Easy Pakistan is planning to use berth at the Karachi Port Terminal (KPT), and Daewoo Gas at the Gwadar Port, for an "integrated LNG project structure," as per the LNG Policy 2011 to import, transport, market and distribute LNG to mainly off-grid customers at the start.[27] During the short term, such a process would help bridge the demand-supply mismatch, as virtual pipelines offer the opportunity to import LNG without the need of an LNG terminal; the berthing vessels can offload at the bowsers/tankers present at the berthing/loading ports. The downside is that it is relatively expensive to distribute LNG via virtual pipelines.

In the medium term, the virtual pipeline system can be made part of an extended network serving the transport sector. For example, in India, a network of LNG fueling stations are being installed along the 5,846 km golden quadrilateral highway network, to help enable the heavy vehicles' switch from diesel to the cheaper fuel.[28] Along similar lines, in Pakistan, the Economic Coordination Committee (ECC) recently allowed OGRA to issue CNG licenses to LNG-based fueling stations with the provision that the stations would neither receive nor later claim an indigenous natural gas supply connection.[29]

S1.7 What would it take to maximize returns from the ongoing deregulation and run the overall gas sector on a sustainable basis?

In order to maximize returns from private sector involvement and ensure sustainability of the overall natural gas sector, it is important to first adopt a holistic approach to resolve the deep-rooted structural and operational challenges. Underpricing of the fuel is a major challenge, and unless the subsidy structure is rationalized and ultimately done away with, the financial viability of the natural gas sector would be difficult. As observed in the previous sections, the global LNG market has been evolving rapidly, with new economies becoming a part of the value chain and the

[26] These are specialized tankers which are used to transport (via road) cryogenic liquids, which are usually liquefied gases being kept at very low temperatures as their boiling points are below -90.0 degrees Celsius (the boiling point of LNG, for example, is -162.0 degrees Celsius).
[27] Source: OGRA (https://www.ogra.org.pk/download/5330).
[28] Source: https://www.exxonmobillng.com/en/About-us/Trending-topics/Indian-virtual-pipeline-initiative/
[29] Ministry of Finance Press Release No. 376. https://www.finance.gov.pk/press_releases.html

nature of purchase agreements and pricing dynamics changing over time. Pakistan is one of the countries that has made a late entry to this market. As such, it has the advantage of first analyzing and learning from the ongoing transformations across more mature markets – such as greater private sector involvement, emergence of flexible term contracts, and increasing share of spot purchases – and accordingly framing its medium- to long-term policy direction.

In this light, the regulatory and structural challenges would need to be addressed to smoothen the supply chain subtleties and satisfy the unmet demand. Furthermore, given the duration of the existing term contracts and the concurrent growing interest of new players to set up terminals and distribution networks, the existing government-controlled import operations would continue to run in parallel with the upcoming private sector involvement in the domestic LNG market. For such a hybrid market to function effectively, however, reorganizations would be required, along the lines of international best practices, to maximize returns from the ongoing developments. In particular, reforms in the following areas could potentially make the domestic LNG operations smoother and more efficient:

1) Introducing some form of price pooling mechanism to ensure that sufficient demand is generated and the public distribution network remains financially viable once private players enter the market

As noted above, the pricing of natural gas in the country is based on the provision of cross-subsidies: the household and fertilizer (feedstock) sectors are subsidized heavily, at the cost of commercial and transport sectors. After the entry of private sector terminal operators and importers in Pakistan, who would be free to sell the imported fuel at competitive rates (with no government intervention), it is likely that the high-priced transport and industrial sectors, and other commercial units, may eventually move out of the public piped gas network – especially as new pipeline capacities come online and the virtual LNG distribution expands.

In this case, the two public utilities will be left with heavily subsidized and low-revenue sectors, since they will be bound to sell both the LNG as well as natural gas at prices negotiated or fixed by the government. These gas utilities will also be bound by the LNG import prices negotiated by the federal government on a long-term basis under the term contracts. In contrast, the private companies could procure spot cargoes at the timing of their choice and as per suitability.

In this regard, a shift towards price-pooling would go a long way towards addressing this challenge. To a large extent, the uniform rate applicable on all the end-users would reduce the incentive to switch suppliers. Furthermore, the potential revenue gains from switching household consumers to the weighted average LNG price, as opposed to the current slab-wise structure, would be significant. As of FY21, Pakistan's indigenous supply of natural gas is unable to meet 29 percent of the total demand for gas by all sectors. This supply gap is estimated to increase to 78 percent by FY30. Assuming that this entire increase in unmet demand is met by imported LNG, then at current rates, the average foregone revenue in case of slab pricing for household consumers would be 55.6 percent of the realized revenue in FY30.

Price pooling may also help generate additional LNG demand in the country. This is important because in the short- to medium-term, where the take-or-pay contract agreements would stay in place for imports as well as terminal operations, additional demand generation can be one way to make prices favorable. It is important that this prospective LNG demand be generated from buyers who currently pay higher gas tariffs (almost at par to LNG rates), such as residential consumers using above 10.64 M ft^3, transport and general industries, ice factories, commercial sector, and captive power plants.

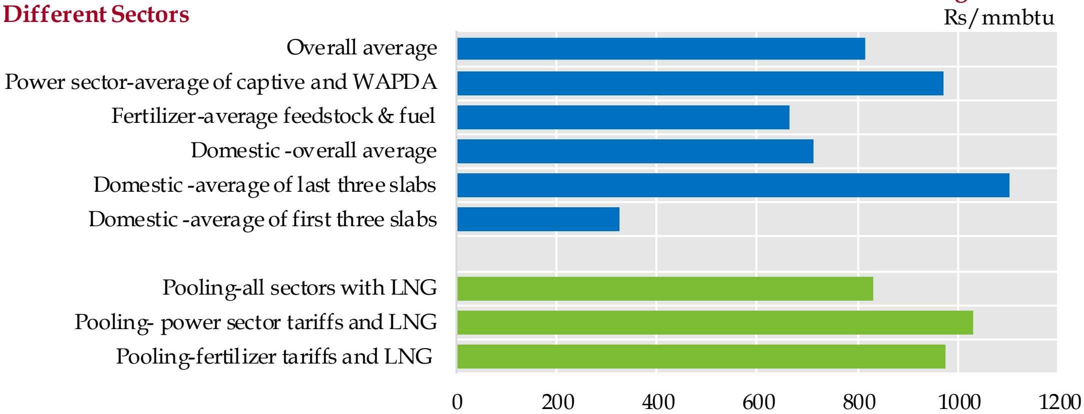
This pooling mechanism has gained traction lately in the countries that are utilizing parallel gas supplies from indigenous sources and imports. For example, India introduced price pooling between natural gas and LNG for one of its largest gas consumers i.e., urea plants, in May 2015 to provide a level-playing field to all fertilizer companies and ensure better management of demand-supply gaps.[30] In Pakistan, the adoption of a similar pricing mechanism may ensure smoother availability of gas to more productive sectors. **Figure S1.14** illustrates the average natural gas tariff for different sectors. The red bars show current averages, whereas the yellow bars suggest the average tariffs, if the LNG tariff rates are pooled with the prevailing rates in different sectors.

2) Supply reliability would also be helpful in generation of additional demand

While price-pooling would help generate additional demand, provisions under the distribution agreements and in the sectoral allocation and management policies add a further layer of uncertainty to gas supplies.

During winter seasons, there is a heightened overall demand for natural gas. In these months, household and commercial gas consumers get prioritized access to both the indigenously sourced and the more expensive imported gas, according to the Natural Gas Allocation and Management Policy 2005. Furthermore, the consumer LNG contracts with gas distribution companies clearly postulate the right of distributing companies in terms of curtailing

Current Average Sectoral Gas Triffs and Comparison With Pooled Prices among Different Sectors **Figure S1.14**



Source: Authors' calculations based on OGRA-notified prices

[30] Source: Ministry of Petroleum and Natural Gas, Government of India.

or discontinuing the deliveries of LNG to industrial and commercial consumers.[31]

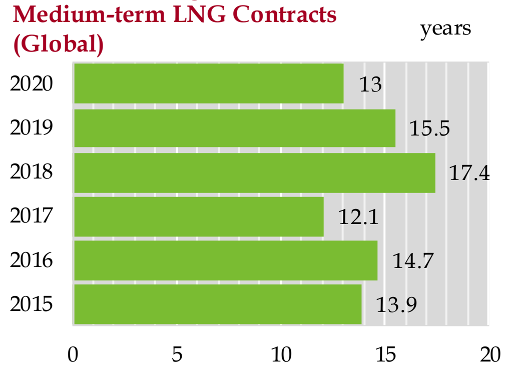
In such a scenario, other sectors, such as general industry and power, remain hesitant to increase their reliance on LNG and prefer to meet their energy needs through the indigenous natural gas (because of cheaper cost) or alternative fuels (to avoid supply uncertainties). Therefore, the government needs to review the allocation and management mechanism of natural gas supplies to incentivize sectors to switch to LNG, which would help utilize the excess terminal capacities and lower the end-user gas prices.

3) There is a need to discover the optimal balance between spot and term purchases

Over the long term, sustainable demand can only be generated when end-consumers are certain of receiving smooth supplies at competitive rates. To a certain extent, private sector participation in LNG trade would fill the additional demand-supply gap while ensuring market efficiency. However, the authorities would have to appropriately weigh the pros and cons before deciding on importing the fuel via long-term contracts or short-term spot purchases.

There exists a trade-off between flexibility and stability when it comes to term and spot imports, with the applicable slope of the former staying relatively unchanged for the duration of the contract and that of the latter varying according to the overall global supply and demand dynamics.

Volume Weighted Average Duration of Long- and Medium-term LNG Contracts (Global) **Figure S1.15**



Source: International Group of LNG Importers

As stated earlier, most of the LNG importing countries arrange their initial supplies through long-term contracts on G2G basis. These contracts assure volume security, which is a primary consideration in building up the capital-intensive LNG infrastructure in the importing countries.

While the average duration of term contracts has still not changed considerably between 2015 and 2020 (**Figure S1.15**), excess supply in global LNG market in recent years has offered buyers relatively favorable conditions for both new contracts and

[31] In the LNG-based contracts between the distribution companies and industrial and commercial units, one of the clauses is as follows: "… the distribution company shall have the right to curtail and /or discontinue deliveries of LNG to the consumer whenever and to the extent necessary in its sole judgement for the service to other customers it may require. The company shall be the sole judge with regard to such conditions and curtailment of deliveries" (Source: OGRA).

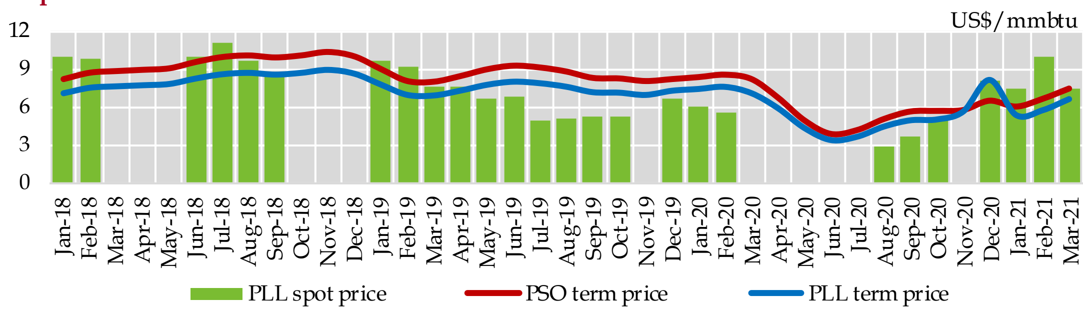
renegotiation of existing ones.[32] In comparison to the falling trend in international spot prices and the lower slopes contracted in the newer agreements, the older contracts appear to be expensive in terms of flexibility and pricing. From 2015 onwards, the newer global contracts began exhibiting more flexibility in terms of pricing mechanism, with increasing adoption of hub-based pricing instead of oil-linked pricing, and inclusion of more flexible price review clauses.[33]

For instance, India's state-owned Petronet had successfully negotiated with Qatar's exporting company RasGas over non-lifting of LNG during 2015, and got a waiver of a take-or-pay payment. The deal also reduced the contract price by nearly half, with the flexibility to lift the 2015 take-or-pay quantity over the remaining term of the 25-year contract; the company also renegotiated the contract price with ExxonMobil.[34] Similarly, in 2019, Japan's utility company Osaka Gas initiated arbitration over its contract with ExxonMobil over the LNG pricing issue.

However, as mentioned before, the volume of spot trade has also substantially increased globally during the last few years, with its share in overall trade rising to 35 percent, from 5.0 percent in 2000.

Import Price of LNG in Pakistan

Figure S1.16



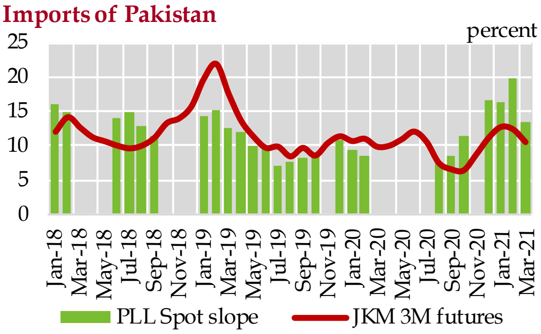
PLL spot price: Price of LNG imports purchased by PLL on spot basis.
PLL term price: Price of LNG imports purchased by PLL in term basis.
PSO term price: Price of LNG imports purchased by PSO on term basis.
Months where bars are absent are the ones in which no PLL spot imports were observed.
Source: Authors' calculations using data from PLL; Engro; OGRA; World Bank; and Bloomberg

[32] "In particular, the LNG supply glut has enabled buyers to seek greater concessions and flexibility in LNG contracting, which has resulted in a trend towards shorter term and more flexible contracts, with new pricing options". The Lantau Group (2019). *Phase Two: Liquefied Natural Gas (LNG) Demand Projection, Procurement Strategy and Risk Management - Executive Summary Report*. Washington, DC: World Bank. Similarly, KPMG, a consultancy, noted that: "The abundant supply picture has changed the negotiating dynamic in the LNG market; buyers will have the upper hand in both new contracts and contractual renegotiations due to both excess supply and locational optionality". KPMG (2016). *Gas, LNG, and Contract Optimization Proposition*. Toronto: KPMG.

[33] Source: Ason, A. (2019). *Price Reviews and Arbitrations in Asian LNG Markets*. OIES Paper NG 144. Oxford: The Oxford Institute for Energy Studies.

[34] India is currently the fourth biggest LNG importer, and is expected to witness the biggest rise in energy demand across the world over the next 20 years (Reference: IEA (2021). *India Energy Outlook 2021*. World Energy Outlook Special Report. Paris: International Energy Agency). This may increase its contract negotiating power, on top of the factors already mentioned in footnote 26.

Applicable Brent Slope on LNG Imports of Pakistan **Figure S1.17**



Note: Brent slope for the Japan Korea Marker prices is derived by dividing the 3 months future JKM prices for a certain month by the preceding three months' average of crude oil spot prices. Slope data for PLL imports is actual.

Source: Authors' calculations using data from PLL; OGRA; Bloomberg

The recent slump in the global LNG market during the Covid-19 outbreak also validated the need to reassess the price and volume conditions agreed under the long-term contracts. For Pakistan, the government can engage in short term contracts with more flexible conditions until the country is ready to pursue more spot purchases under the private sector's participation.

However, it is also important to note that the volatility in the spot market means that there would be times when spot procurements may end up being costlier than the term procurements. As shown in **Figure S1.16**, although Pakistan's spot procurements were cheaper than term procurements most of the time, there have been instances when spot procurements were costlier. This may be the case during winters, when excess demand almost always results in a substantial rise in global prices. However, better demand forecasting and adequate storage capacity can help alleviate these concerns and allow for better spot decisions.

Here, it is also important to note that so far, spot rates for LNG imported by Pakistan had been higher than LNG futures in 2018;[35] lower in comparison to most of 2019 and early 2020, and, after a long pandemic-induced break, much higher than the futures prices in the second half of 2020, as the actual price rose due to a demand glut in the East Asian markets (**Figure 1.17**). All in all, this makes a strong case of advertising and finalizing orders earlier than usual during winters in order to lock in rates, which tend to increase as the season progresses.

4) Improvements in demand forecasting and decision-making in both public and private sectors

Given the fact that nearly a third of cargoes at PLL arrived on spot basis during FY20, timely and accurate demand forecasting by public procurement agencies is important because the incoming private players would secure the rights to utilize the auctioned excess capacity of the terminals.

Currently, the demand forecasting capability and practices are not at a satisfactory level, which – in the presence of a lengthy public procurement process – results in tender delays and pricier bids. Also, smooth importing on a regular basis would eventually require more than one-at-a-time auction process, which would further necessitate timely communication and

[35] Future international prices of spot purchases, in terms of slope of Brent, are arrived at by using the three months forward rate of Japan Korea Marker (JKM) for any given month (for example, the JKM futures price for April 2020, as on end-January 2020) and dividing it by the average of spot crude oil prices during the preceding three months (January, February, and March, 2020).

dissemination of demand forecasts along the whole supply chain.

For smoother operations and to ensure that imports are finalized at competitive rates, importers need to notify the terminals around three to four months in advance to secure the needed cargoes. In this regard, the PPRA procurement rules may also be revised to minimize the time between the invitation and opening of bids, and between result announcement and contract finalization. With private importers eventually coming into the market, further improvements would be witnessed on this front, provided that these players would not have to follow PPRA regulations. Although the government has recently exempted PLL from the PPRA rules when securing spot purchases, these exemptions are time-bound, and would also not be sufficient to shorten the import process duration. A more effective solution would be to introduce sector-specific clauses within the PPRA rules for LNG imports. This would provide a legal cover to the importers, help reduce costs, and speed up supplies to the end-consumers on a sustainable basis.

5) A consistent policy on the treatment of UFG losses borne by the Sui companies

According to the Ministry of Energy (Petroleum Division), unaccounted for gas (UFG) "is a phenomenon of gas loss which is contingent upon occurrence of various technical factors when gas flows from fields to end consumers. It is calculated as the difference between metered gas volume injected into the transmission and distribution network (Point of Dispatch/Delivery) and the metered gas delivered to the end consumers (Consumer Meter Station) during a financial year".[36] The rate of UFG of SNGPL stood at around 12 percent (about 52,577 mmcf), while that of SSGCL stood at around 18 percent (70,810 mmcf) in FY19. This compares to the UFG benchmarks of 1.0-2.6 percent in the advanced economies (US, UK, Canada, New Zealand and Germany), and 4.2-5.0 percent in developing economies (Turkey, Russia and Bangladesh).[37] Meanwhile, OGRA has allowed a UFG charge of 6.3 percent for domestic consumers. This means that the unmet amount becomes part of the distribution companies' losses.

The current revenue calculation mechanism disproportionally incentivizes network expansion over pipeline maintenance. This is because new connections increase the utility companies' fixed assets, and the companies are guaranteed a market-based return of 17.43 percent on their net operating fixed assets.[38] As a result, residential connections have risen by an average of 504,722 per annum (6.5 percent YoY average growth) during FY16-19, compared to per annum average additions of 1,753 commercial consumers (2.8 percent) and 111 industrial consumers (1.0 percent) during the same period. Continued addition of new connections, particularly residential, without addressing the high UFG rates and low slab pricing would mean that the inefficiencies in

[36] Ministry of Energy (2020). *Unaccounted for Gas (UFG) Gas Report FY-2020*. Islamabad: Ministry of Energy (Petroleum Division).
[37] KPMG (2017). *Oil & Gas Regulatory Authority Un accounted for Gas – Study*. Final Report July 2017. Karachi: Klynveld Peat Marwick Goerdeler.
[38] OGRA Annual Report 2018-19.

the gas distribution network would keep on rising.

Encouragingly, the federal cabinet recently ratified a three-year plan approved by the ECC to trim the UFG losses of the Sui companies. The reduction plan, which is based on yearly UFG reduction targets, has two components: tracking against 30 key monitoring indicators (KMIs)[39] as advised by OGRA; and UFG reduction plans in law and order affected areas. The overall objective is to reduce the UFG losses of SNGPL and SSGC by 4 percent (18,240 MMCf) and 9.55 percent (40,629 MMCf), respectively, in three years.

In FY20, a number of improvements took place with regards to the UFG reduction policy. For instance, SSGC replaced and tested 1,244 industrial meters against the target of 1,560 meters. Moreover, over 2,758 raids were conducted against the illegal use of gas, resulting in a claim of 390 mmcf of natural gas. Meanwhile, in Karak, the region contributing the most to the UFG losses, the HR strength of SNGPL was increased, and work was expedited to lay the legal gas pipeline network and install gas connections. During FY18-20, a total of 6,466 illegal taps in the distribution and transmission network were removed and 160 FIRs lodged in the Kohat district for gas theft.

S1.8 The Way Forward

Ensuring energy security lies at the core of a country's energy policy. In case of Pakistan, the swift shift towards imported LNG was the right step, keeping in view the falling indigenous gas supplies. At this point, the incoming capacity expansions in terminals and pipeline networks mean that LNG's share in the country's energy mix would continue to increase. Recently, Pakistan has also signed another G2G deal with Qatar to import 200 mmcfd (roughly two cargoes a month) of LNG from 2022 onwards at an applicable Brent slope of 10.2 percent, which would then increase to 400 mmcfd (four cargoes per month) after three years. This contract entails the option of increasing the import volume during high-demand months, for example during winters, and also has a price renegotiation clause of four years.

With LNG imports set to rise substantially over the coming years, it is crucial to devise ways to address the mindset of cheap availability of natural gas in the country. Due to the prevalence of extensive cross subsidies, various segments of the economy, in particular fertilizers and household sectors, have taken the availability of subsidized natural gas for granted. In hindsight, the policy of subsidized natural gas has entailed significant economic cost for the country, with the indigenous reserves deteriorating at a rapid pace as excessive consumption of the fuel was encouraged. Going forward, consumers would have to quickly readjust to the more expensive imported LNG. Here, it is pertinent to mention that natural gas as a heating source is less efficient than electricity, and that the consumption in terms of energy equivalent of running, say, a 35-gallon gas geyser (29,000 BTU/hour) is much higher than that of a 1.5-ton air conditioner (18,000 BTU/hour).[40] However, in Pakistan, the bills consumers face with regards to the former

[39] The KMIs pertain to network segmentation, underground leak survey, industry meters proving, and overhead leakage repairs, etc.
[40] SBP Annual Report for 2012 on the State of Pakistan's Economy.

are substantially lower than those for the latter.

The government has to start passing on the impact of higher LNG prices to the consumers via an appropriate price pooling mechanism; otherwise, it risks the formation of a circular debt situation akin to the one prevailing in the electricity sector. Furthermore, given that the domestic consumption of natural gas is expected to increase sharply going forward, an increase in prices would help cut down extravagant household consumption, which would in turn help reallocate the cheaper fuel to the power and industrial sectors to decrease the cost of energy generation and increase the fuel's usage in value-addition segments. The impact of subsidy rationalization on the low-income quintile can be compensated via targeted cash transfers, which is a more efficient way of providing social protection.

In addition, the relevant authorities also need to develop a long-term strategy that, among other aspects, also focuses on expanding the indigenous reserves base of natural gas. According to the US Energy Information Administration (EIA)'s 2013 Technically Recoverable Shale Oil and Shale Gas Resources report, Pakistan held sizeable shale gas reserves of 105 trillion cubic feet (Tcf). Pakistan's Ministry of Energy (Petroleum Division) also completed a study in 2015 on the evaluation of shale oil and gas resources in the Lower Indus Basin and the Middle Indus Basin with the help of USAID. The results revealed that Pakistan's shale gas geological resources amounted to 95 Tcf recoverable reserves. However, the exploration companies face many challenges in developing these resources because of complex geography, environmental constraints, and low natural gas prices in the country. Thus, the country needs to develop preferential policies (increasing the wellhead prices to begin with) and conduct pilot projects as early as possible, to encourage domestic and foreign oil and gas companies to plan investments.

Beyond gas, the government also needs to take an all-inclusive view of the energy mix in the country, given that renewables, especially solar, have appeared as low-cost and crucial alternatives in the midst of worsening climate change situation. At present, the renewables' share is only 4 percent in Pakistan's installed power generation capacity and 2 percent in power generation. However, the incentive to switch to these sources is significant. According to the World Bank's 2020 Global Photovoltaic Power Potential report, utilizing just 0.071 percent of geographical area of Pakistan for solar photovoltaic (solar PV) power generation would be sufficient to meet the country's current level of electricity demand. This makes the country rank 49th out of 210 economies in terms of average solar power generation potential.[41] Furthermore, bringing the share of renewables to at least 30 percent of the total generation during the next 20 years would also lead to a reduction of US$ 0.002 for every kWh consumed in Pakistan, or around US$ 5 billion (in today's discounted terms).[42]

[41] Energy Sector Management Assistance Program (ESMAP) .2020. *Global Photovoltaic Power Potential by Country*. Washington, D.C: World Bank Group.
[42] Schmitt,Karsten; Reithe,Georg; Hoepp,Julia; Schreider,Achim.2020. *Variable Renewable Energy Integration and Planning Study* (English). Pakistan Sustainable Energy Series Washington, D.C.: World Bank Group.

Annexure-I – Common Abbreviations and Conversion Factors used in LNG Trade

Conversion Factors for Natural Gas Units

Input unit	Output unit	Multiply by
cubic metres (m3) LNG	cubic metres (m3) natural gas	615
cubic metres (m3) natural gas	cubic metres (m3) LNG	0.001626016
cubic metres (m3) LNG	cubic feet (cf) natural gas	21,718.52
cubic feet (cf) natural gas	cubic metres (m3) LNG	0.000046044
Million cubic feet (mmcf)	Million british thermal units (mmbtu)	1,037
million tonnes LNG	billion cubic feet (bcf) natural gas	48.0279467
billion cubic feet (bcf) natural gas	Million british thermal units (MMBtu)	1,000,000
billion cubic feet (bcf) natural gas	million tonnes LNG	0.020821211
million tonnes LNG per year (MTPA)	billion cubic feet natural gas per day (bcf/d)	0.131584156
billion cubic feet natural gas per day (bcf/d)	Million tonnes LNG per year (MTPA)	7.59974192

Common abbreviations and their description

Abbreviations	Description
cf	cubic feet
mcf	thousand cubic feet
mcd	thousand cubic feet per day
mmcf	million cubic feet
mmcfd	million cubic feet per day
bcf	billion cubic feet
bcfd	billion cubic feet per day
tcf	trillion cubic feet
m3	cubic metre
Btu	British thermal units
mmbtu	million British thermal units
MTPA	million tonnes per annum (of LNG)
TOE	Tons of oil equivalent – amount of energy released by burning one tons of crude oil

Source: North American Cooperation on Energy Information; International Energy Agency

Annexure-II – Computation of OGRA Notified LNG Prices

Computation on LNG Weighted Average Pricing for Feb 2021 (quantities in mmbtu; price in US$/mmbtu)

		PSO	PLL
A	**Number of cargoes**	**6**	**3**
B	**Quantity Received**	**19,200,000**	**9,600,000**
C	Retainage 0.6 % of B for PSO and @ 0.778% of B for PLL	115,200	74,692
D	**Quantity Delivered at Terminal (B-C)**	**19,084,800**	**9,525,308**
E	Transmission Loss (0.38% of D for SNGPL; 0.12% for SSGC)	72,522	36,196
F	Distribution Loss: (6.3 percent of D for both SNGPL and SSGC)	1,202,342	600,094
G	**Total loss Including Retainage (D+E+F)**	**1,317,542**	**674,786**
H	Percentage Losses (G/B*100)	6.86	7.03
I	**Quantity available for Sale (B-G)**	**17,882,458**	**8,925,214**
J	**LNG Price (DES) (see notes)**	**6.7773**	**8.5366**
K	PSO/ PLL other imports related costs (see notes)	0.5234	0.6337
L	PSO / PLL margin (2.5% of J)	0.1694	0.2134
M	Terminal Charges (based on quantity imported; see notes)	0.3786	0.6956
N	**LNG Cost (J+K+L+M)**	**7.8487**	**10.0793**
O	Retainage adjustment (0.6% or 0.778% of N, whichever applicable)	0.0471	0.0784
P	T & D volume adjustment (0.38% of N plus 0.63% of N; see notes)	0.5309	0.6830
Q	LSA management fee (SSGC/PLTL) (fixed; see notes)	0.0250	0.0250
R	Cost of supply-SNGPL (fixed; see notes)	0.2621	0.2621
S	Cost of supply -SSGC (fixed; see notes)	0.1012	0.1012
T	**Total LNG price without GST (N+O+P+Q+R+S)**	**8.8153**	**11.2296**
U	Quantity available for Sale (same as in I)	17,882,458	8,925,214
V	**Total cost of LNG (T*U)**	**157,639,975**	**100,226,650**
W	Total LNG cost (PSO & PLL) (sum of two prices in V)	257,866,625	
X	Total quantity available for sale (PSO & PLL) (sum of two volumes in U)	26,807,671	
Y	**Weighted Average Sale Price without GST (X/W)**	**9.6191**	

Notes:

A. The number of monthly cargoes received in respective terminals

B. Total quantity of the imported LNG in MMBtu

C. Guaranteed retainage as per the Operation and Service agreement (OSA) between the terminal owner and terminal operator. These are charged as compensation for fuel for the port facility. Retainage charges are 0.6 percent for PSO imports and 0.778 percent for PLL imports.

D. Quantity delivered net of the volume withheld as retainage.

E. Transmission losses as permitted for the Sui companies by OGRA. Currently, the rate is 0.38 percent for SNGPL and 0.12 percent for SSGC. In the table above, SNGPL's transmission rate has been taken for the LNG price determination
F. Transmission losses as permitted for the Sui companies by OGRA. Currently, the rate is 6.3 percent for SNGPL and SSGC
G. Total volume loss is inclusive of retainage and either transmission or distribution losses, depending upon the stage of supply. In the table above, distribution losses are added as the computation is for LNG price charged to end-consumers
H. Losses as a percent of total imported volume
I. LNG quantity, net of retainage and transmission/distribution losses, which is available for further distribution to the end-users
J. Delivered ex-ship price (DES) is calculated by applying the agreed upon Brent slope under the term or spot contracts on the average of the last three months' crude spot prices. The resulting US$/MMBtu prices of each cargo would then be used to reach to a weighted average DES price for the two importers, PSO and PLL, based on quantity of imported LNG. Under the DES price mechanism, the seller bears all costs and risks associated in bringing the goods to the port of destination. The buyer, then, is responsible for all costs necessary to unload the goods and clear them through customs.
K. Other import-related costs include handling/unloading charges and charges under the Sindh Infrastructure Development Cess (CESS)
L. The margins allowed to the importers on LNG purchases. Presently, the rate is 2.50 percent of the DES price.
M. Terminal charges are based on capacity charges. For PLL, these charges are US$ 245,220 per day and US$ 0.009 per MMBtu, with the average working out @ US$ 0.4177 per MMBtu. For PSO imports (Engro Elengy terminal), the average rate is US$ 0.479 per MMBTu. In addition to this, Port Qasim charges US$ 600,000 per vessel. Note that these charges are with regards to full capacity utilization. Given that PLL's capacity utilization is around 60 percent, the resultant terminal charges rise to around US$ 0.7 per MMBtu
N. This is the total LNG cost, inclusive of the DES price and the aforementioned margins and charges.
O. Retainage costs are carried forward and charged from the end-consumers. Resultantly, total LNG cost is increased by 0.6 percent and 0.778 percent for PSO and PLL, respectively
P. A similar adjustment is made for the transmission and distribution losses. Total LNG cost, calculated in stage N, is increased by 0.38 percent and 6.3 percent, respectively, to accommodate transmission and distribution losses
Q. These are the margins of distribution companies, SNGPL and SSGC, under the LNG Supply Agreement (LSA) with the LNG importers (PSO and PLL). The level is fixed at US$ 0.02621 per MMBtu
R. Cost of supplying LNG gas borne by the SNGPL
S. Cost of supplying LNG gas borne by the SSGC
T. Total LNG cost, inclusive of the DES price, importer margins, terminal charges, retainage and T&D loss adjustments, cost of supplies to the pipeline companies, and the margins of the distributors.
U. LNG quantity, net of retainage and transmission/distribution losses, which is available for further distribution to the end-users. Same as in stage I
V. Total price is calculated by multiplying the total LNG quantity available for sale with each importer by the total LNG cost computed in stage T
W. Summation of the total costs of PSO and PLL available LNG supplies, as computed in V
X. Summation of the total quantity of PSO and PLL available LNG supplies, as computed in U
Y. Final weighted average LNG price for the month computed by dividing total available supplies over total cost.

Source: OGRA