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Analytical Study to Assess the Potential of Gas / LNG for Regional Energy Cooperation in BBINS Region

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This study is made possible by the support of the American people through the United States Agency for International Development (USAID). The content of this study does not necessarily reflect the views of USAID or the United States Government.

IRADe-SARI-27 (2021)

Analytical Study to Assess the Potential of Gas/ Liquefied Natural Gas (LNG) for Regional Energy Cooperation in BBINS (Bangladesh, Bhutan, India, Nepal, Sri Lanka) Region

May 2021

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तरुण कपूर
सचिव
Tarun Kapoor
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The Indian economy is currently at an inflection point, with a strong rebound in economic activities poised to once again make it one of the fastest growing economies in the world. The commercial and industrial activities are moving back to pre-COVID levels, and the rural economy has held on to its resilience. This strong comeback of the economy would spur employment and significantly improve social development metrics. Like in all rapidly developing economies, energy will play a crucial role in supporting this large-scale growth.

As India takes on a leadership role in the sustainable development and combatting climate change, the energy roadmap of the country is also undergoing a considerable shift. As part of its commitment in the Paris Agreement of 2015, the country is steadfast in its resolution to cut greenhouse gas emissions intensity of the GDP by 33% to 35% from 2005 levels, and increase non-fossil fuel power capacity to 40%, by 2030. Government of India has also set a goal of installing generation capacity of 175 Gigawatt of renewable energy by 2022. In our view, gas-fired power plants can perform the critical role of grid balancing to ensure continuous supply of power.

In this scenario, natural gas will be an increasingly important part of the country's energy basket. It is well established that natural gas is the cleanest fossil fuel which emits negligible particulate matters and lowest air pollutants as compared to coal and oil. At present, India consumes about 170 mmscmd of gas. The country plans to increase the share of gas in India's primary basket from existing 6.2% to 15% by 2030.

The Government of India has undertaken several important initiatives to increase the share of gas, including the recent "One Nation, One Gas Grid" scheme. Our honourable Prime Minister has affirmed that a gas-based economy will be crucial for an Atmanirbhar Bharat. In the past few years, the government has worked on building infrastructure for boosting the growth of natural gas in the country. It has increased the coverage of CGD network in the country to cover 70 percent of India's population across 50 percent of the country's geographical area and is taking steps to further increase the coverage of CGD network in India

The key drivers of the demand for natural gas are its role as the bridge fuel and the economic advantage for consumers over fuels like petrol and diesel, for long haul transportation, industrial, commercial sectors. The demand growth will be supported by a spurt in the growth of pipeline infrastructure, city-gas distribution, LNG receiving terminals. These will be further reinforced by policies, regulations and tighter emission norms, which encourage investments by private players in the gas value chain, from exploration to supply and distribution.

I congratulate IRADe for conducting the "Analytical Study to Assess the Potential of Gas/LNG for Regional Energy Cooperation in BBINS Region" in association with USAID and other stakeholders.

It is a relevant and timely study that analyses the crucial role of natural gas/LNG in meeting India's growing energy demands, as well as assessing its potential for regional energy cooperation in the BBINS region.

I hope the study will stimulate rich discussions among South Asian stakeholders to enhance the potential of natural gas as a cheaper and cleaner alternative to polluting fossil fuels, as well as encourage optimisation of the availability consumption paradigm for the stakeholder nations for mutual benefit of all . .

Tarun Kapoor

[Tarun Kapoor]

Foreword

The U.S. Agency for International Development (USAID) has been working to enhance regional energy cooperation in South Asia since 2000 through its South Asia Regional Initiative for Energy (SARI/E) rogram. The first three phases of the program focused on building trust, raising awareness, and assessing potential transmission interconnections. The current and fourth phase of the program, called South Asia Regional Initiative for Energy Integration (SARI/EI), which was launched in 2012, focuses on promoting regional energy integration through cross-border power trade. This is being implemented by the Integrated Research and Action for Development (IRADe), a leading South Asian think tank.

The SARI/EI program is an integral part of USAID's support for sustainable and secure energy markets throughout the Indo-Pacific region, by helping governments to expand clean energy development, promote energy diversification, and strengthen energy security. In its fourth phase, SARI/EI is also looking at trade of other energy resources, including natural gas.

The South Asia region has immense economic and socio-economic growth potential. In the post-COVID recovery, the region can play an instrumental role in building a cleaner, greener, and sustainable future with universal access to affordable, reliable, and clean energy. Regional energy cooperation is critical for facilitating South Asia's transition to a thriving and sustainable economy. While electricity trading is already underway in the region, especially among the Bhutan-Bangladesh-India-Nepal (BBIN) countries, gas or liquified natural gas (LNG) is a potential area for cooperation to promote diversification and enhance energy security in the region.

Recognizing the importance of Gas/LNG as an important constituent of South Asia's energy basket, this SARI/EI report seeks to assess the potential of gas or LNG for energy cooperation in the BBIN region including Sri Lanka. Given the current increased focus on gas by all the countries in the region, the report will be a useful reference point for facilitating discussions to strengthen energy cooperation in the region.

I would like to take this opportunity to acknowledge the excellent work done by the SARI/EI team at IRADe, and Mr. Swami Prasad Dayal in developing the report. I hope the findings of this report will be useful for all the countries in the region.

Thank you

Julia Kennedy

Julia Kennedy

Indo Pacific Director (A), USAID/India

Preface

Integrated Research and Action for Development

We are pleased to present the **"Analytical Study to Assess the Potential of Gas/LNG for Regional Energy Cooperation in BBINS Region"**, developed under the South Asia Regional Initiative for Energy Integration (SARI/EI) project, supported by the USAID and implemented by Integrated Research and Action for Development (IRADe).

This Study assesses the potential for exploration, production and trade of natural gas in the BBINS (Bangladesh, Bhutan, India, Nepal, Sri Lanka) region. The study examines in detail, the various issues and factors related to – (1) Dependability on LNG and affordability on a long-term basis; (2) Economic value that natural gas/ LNG offers over other fuels to the consumers in the region; and (3) Potential and opportunities for regional cooperation.

The BBINS region is short of indigenous/domestic gas reserves and supplies. It is a net importer of gas in the form of LNG. To support its growth, transition to renewables and keep its NDC targets in mind, the region needs to look at natural gas as a clean, economical and flexible fuel option. A large share of the global demand for LNG is likely to emerge from India, Bangladesh and Pakistan. On the other hand, the LNG producing markets have grown significantly and are on the lookout for new consumers. The beginning of trade within the BBINS region provides an opportunity for strategic partnership for collective sourcing of LNG at economical prices from the international markets, especially because Bhutan and Nepal are landlocked and Bangladesh needs support to facilitate LNG imports.

The report explains the gas demand/supply position globally and in the BBINS countries, including the trends in demand for the next 20 years. It explains how having a gas grid connecting the BBINS countries to the extent feasible, will result in optimizing of gas transportation and LNG terminal infrastructure, and reduced gas prices. It also discusses the possibility of having a gas exchange and gas trading hub in the South Asia region for short term exchanges, and a greater say, by the Region, in dictating natural gas prices.

This report advocates that while gas is a potential alternative for energy security, imports would have to be stepped up to fulfil the demand. It concludes that LNG trade thus presents a great potential for the region and region specific solutions would be required for gas to emerge as a reliable energy source supported by a stable market. The report estimates the potential benefits from intra-regional trade in gas in the BBINS to be about USD 1.2 billion/annum in 2025, which can go up to USD 1.9 billion/ annum in 2030, and approx. USD 3.6 billion/annum by 2040.

The draft Report was circulated to senior Government officials, decision-makers and other experts in the Gas sector in the BBINS countries. Their feedback and thoughts have helped make this report more robust and relevant to all the stakeholders.

I hope that this report will serve as a starting point for enriching discussions on enhanced energy cooperation for trading of natural gas in the BBINS region. I am grateful to USAID for their continued support in the preparation of this report. I sincerely thank Mr. Swami Dayal Prasad, Senior Consultant, SARI/EI, IRADe, for his invaluable contribution in drafting this report. I appreciate the research team at SARI/ EI Secretariat /IRADe, for their valuable inputs and guidance through sustained efforts in ensuring that the report is completed despite the restrictions posed by the lockdown.

Jyoti Parikh

Dr. Jyoti Parikh
Executive Director
Integrated Research and Action for Development (IRADe)

photo-courtesy-of-shell-91231

Executive Summary

Background

The Report on Global and Regional (BBINS) Perspective on Natural Gas (July 2019) had reviewed the global gas environment and the domestic production and demand in the BBINS nations in South Asia. The report evaluated the reserves in the Bangladesh, Bhutan, India, Nepal, Sri Lanka (BBINS) countries along with the production and demand. Only India and Bangladesh possess gas reserves and produce gas. The major constraint that limits its consumption is its availability. In Bangladesh, the reserves are depleting and production is on a decline, while in India, the domestic production declined after 2011-12, and has now started to increase. Both the countries import LNG, and the dependence is likely to increase. Sri Lanka has not been able to monetise its reserves in the off-shore basins. Nepal appears to have minimal reserves, while Bhutan does not have any oil or gas reserves. The report advocates that while gas is a potential alternative for energy security, imports would have to be stepped up to fulfil the demand. Import by pipelines from Central Asia would need to cross through Afghanistan and Pakistan, which may not be feasible due to security concerns. It concludes that LNG trade thus presents a great potential for the region and region specific solutions would be required for gas to emerge as a reliable energy source supported by a stable market.

This report explores the issues and factors for

- Dependability on LNG and affordability on a long-term basis
- Economic value that Natural gas / LNG offers over other fuels to the consumers in the region
- The potential and opportunities for regional cooperation

The report is structured in two parts. Part A is focussed on understanding the value chain and status of gas demand and supply in different regions of the globe, LNG production and supply. Part B deals with the energy environment in the BBINS nations in South Asia and the opportunity that natural gas offers in clean and efficient energy source.

Global LNG Scenario

The LNG manufacturing plants are capital intensive projects. It may take up to 8-10 years time from conceiving an LNG project to delivery of the first cargo. As LNG is a cryogenic liquid, its transportation requires special vessels which are more expensive than those for crude and petroleum products and cannot be used for other commodities. LNG production and trade began with firm long-term agreements but has been steadily switching to spot and short-term trade. Non long-term trade has increased from 16% in 2010 to about 48% in 2019. The use of LNG is growing on account of its acceptance as an economic and cleaner fuel across the globe. As per International Gas Union's (IGU) World LNG Report 2020, global markets have now grown in size with 20 exporting countries and about 42 importing countries at the end of 2019. The exporting regions are Eurasia, the Middle East and North America, whereas Asia is the largest importing region. To sum up, this part explores the status of LNG's long-term liquefaction capacity/availability (existing under implementation and expected future capacity additions) and LNG Shipping / transportation, receiving and re-gasification terminals for vaporizing the LNG, supply and demand scenario, factors including affordability, influencing trade and the various emerging trends in the trade practices over the next two decades.

Global LNG Capacity: As per IGU World LNG Report 2019 & 2020, the global liquefaction capacity witnessed a CAGR of 7% during the period from 2016 to 2018. In 2019, the growth was 11% over 2018 and liquefaction capacity of 42.5 MTPA was added, taking the global liquefaction capacity to 430.5 MTPA. In 2019, Final Investment Decision (FID), a decision taken by the board of directors of an oil / gas company to go ahead with the project, was reached for a record 70.6 MTPA, which is 40% higher than the highest ever annual FID for 50.4 MTPA achieved in 2005. The IGU 2019 report indicated that LNG capacity of 101.3 MTPA was under construction, with two-thirds coming up in USA alone. As in May 2020, FERC approved under-construction capacity in USA stood at 9.78 Bcfd(Billion cubic feet per day)(nearly 77 MTPA (Million Tonnes per annum)). By 2023, USA is likely to emerge as the country with the largest LNG capacity. Besides, in the USA, FERC has approved about 22.922 Bcfd (nearly 182 MTPA) capacity which is to be constructed and awaiting FID. Qatar plans to add another 49 MTPA and Russia too has plans to add about 21 MTPA.

LNG Shipping capacity

As per IGU, by the end of 2019, the active fleet of LNG vessels stood at 541 vessels. During 2019, 42 new vessels were delivered (against target deliveries of 43 vessels for the year), which is a growth of about 8.4% and slightly behind the global growth trade of 13% over the previous year. As per a September 2019 report by Argus, the order book for LNG vessels had expanded to 135, to be delivered over the next three years. With limited scrapping, the global LNG fleet size is likely to grow to above 600 LNG carriers by 2020. As per Wood Mackenzie Group, availability of LNG Vessels is likely to remain in surplus till 2022. The competition between shipyards in South Korea, Japan and China has brought down the prices of vessels to well under $1000 -1100 per cubic metre.

Global LNG Receiving capacities

By February 2020, the global RLNG capacity was 821 MTPA across a total of 36 markets. Asia-Pacific countries together have 60% of the global capacity, followed by Europe (20%) and North America. While the average utilization in 2019 was 43%, it is higher in countries with growing demand like Chinese Taipeh (113%), China (74%), Pakistan (85%), India (67%), and Bangladesh (65%). Asian countries led by China, India and other South Asian and South East Asian counties, are key to the future growth in RLNG capacity additions. China, India and Pakistan lead the pack with FID achieved for 60 MTPA capacities. Asian countries also have plans for nearly 240 MTPA of capacity addition, presently in the Pre-FID stage. The Floating Storage and Regasification Units (FSRUs) support quicker and more flexible capacity addition, as seen in Egypt, Pakistan and Bangladesh, and have emerged as popular options for importing LNG at short notice.

LNG Contracts and pricing and recent trends

Post 2012, there has been a distinct shift in the terms of LNG contracts and pricing. These are shorter terms of contracts. There has been an increase in the number of short-term contracts and their share in the LNG Trade. There has been a distinct reduction in long-term contracts, reduction in average volume per contract, a shift from Oil-linked to Gas Hub-linked/ Hybrid indices, and softening of the oil indexation from 14% to around 11% in the mid-term and long-term contracts leading to more affordability.

Nearly 43 MTPA out of the 70.6 MTPA of FID for new capacity addition in 2019 have been committed without long-term contracts, which is an indication of more liquidity and short-term trade in future. Nearly 45% of the order books are not backed by firm long-term ship charters, an indication of more vessels to be available for short-term/spot trades. The numbers of destination ports have increased to 134 across 42 countries and standardized contracts are being developed to facilitate fast contracting required for spot/short-term trade for meeting volatility demand with minimal delays. These factors are indicative of LNG gaining its acceptance in terms of affordable and dependable fuel.

LNG Demand-Supply

In its LNG Outlook 2020, Shell has projected that Natural gas & LNG shall meet 43% of the growth in global energy demand till 2040, with renewable sources accounting for 37% growth. Asian markets continue their growth and constitute 74% of the growth in LNG demand from 2019 to 2040. Further, demand may also rise due to decline in the existing gas production and pipeline supplies in many markets. The International Maritime Organization (IMO) 2020 regulations for marine fuels also lead to a distinct increase in demand of LNG as bunker fuels used for fuelling ships. Shell projects that the global LNG demand for the different gas markets is likely to be around 725 – 750 MTPA by 2040. These demand numbers are also close to the LNG demand projections for 2040 by IEA in its 'Stated Policy' scenario in the World Energy Outlook 2019. It may be seen that after taking into consideration the LNG production from projects under construction or the capacity that has achieved FID, there is a gap of about 250 MTPA, which would have to be met from new capacity addition. The FERC approved liquefaction capacity to be constructed in the USA alone is about 22.922 Bcfd (nearly 182 MTPA). Also, as per IGU, about 907 MTPA of proposed LNG capacity are in the Pre- FID stage across the globe. This allays the fear of shortages of LNG availability in future till 2040.

State of gas infrastructure and potential in BBINS nations

Natural gas (NG) is less polluting than other fossil fuels for power generation, as also for transportation, household and industry sector and also offers economic advantage in preference to other fuel options. It is more suitable than coal for balancing the intermittencies of power generation by variable renewable energy sources.

At present, only India and Bangladesh have commercially exploitable gas reserves and produce domestic gas. Sri Lanka has succeeded in gas discoveries in the off-shore Mannar Basin and is pursuing a comprehensive exploration programme for achieving commercial production of gas from its basins. In spite of naturally occurring gas seeps and some finds in the Kathmandu Valley, Nepal is yet to achieve any commercially viable discovery. Bhutan has some coal reserves, but does not have any gas reserves. Country-wise summary-analysis is as follows:

India

At present, India consumes about 170 mmscmd of gas. The country plans to increase the share of gas in India's primary basket from existing 6% to 15% from existing 6% to 15% by 2030. Its existing pipeline network of about 17,000 Kms is skewed and provides access to only about 25% of its population. However, 16 major trunk pipelines of about 15,000 Kms are under construction. With the successful bidding of 136 geographical areas in the bidding rounds of City Gas Distribution (CGD) networks in 2018 & 2019, nearly 70% of the country's population and all major industrial and commercial belts will have access to gas in the coming years. The key drivers of demand are economic advantage for consumers over fuels like petrol and diesel, in the transportation, industrial, commercial sectors, supported by a spurt in the growth of pipeline infrastructure, city-gas distribution, LNG receiving terminals. These are further reinforced by policies, regulations and tighter emission norms, which encourage investments by private players in the gas value chain, from exploration to supply and distribution. India has successfully utilized 'Small-scale / Virtual LNG Supply' mode utilizing trucks/lorries with Cryogenic Containment system and LNG storage and vaporizers at multiple consumption points, which has been found to provide quick access, low investment, lower risks, and competitive prices for supplies in areas where gas pipelines have not reached as yet.

About six LNG receiving terminals are in operation and another four terminals are under construction. Two scenarios have been envisaged for projecting the demand, supply and the gap. It is expected that if LNG receiving terminals and the pipelines come as scheduled, there may be surplus capacity for about 50-60 mmscmd by 2025. This surplus capacity can be used for trade. Post 2030, the country might need additional LNG receiving capacity.

India has about 25 GW of gas-based power plants. However, these plants are under - utilized as cheaper options from coal-based and renewable plants are available. The National Electricity Plan prepared by the CEA, and a subsequent CEA study on Optimal Generation Mix, have forecast about 300 GW of capacity addition from Solar PV and 140 GW from Wind by 2029-30, and part utilization of gas-based capacity along with Battery Energy Storage systems to meet the flexible requirement of the demand. However, with the prevailing Capex of the Battery Storage, this report analysed the levelized tariffs and concluded that utilization of the already installed gas-based capacity is not only technically suitable to meet the flexible needs of the power system, but with the recent decline in the LNG prices, also provides for more economical energy for balancing the grid.

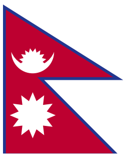
Bangladesh

The discovery of gas has helped Bangladesh in its development and economic growth over the last two / three decades. Gas accounts for nearly 66% of the total commercial energy consumption and as such, Bangladesh is truly the only gas-based economy in the BBINS region. Till 2018, the country met its demand from domestic production. Thereafter, its gas production has declined while the demand has increased. Bangladesh has hired two Floating and Storage Regasification Units (FSRUs) on 'Build-Own-Operate-Transfer' (BOOT) basis for a 15-year term. The power sector (utility and captive) consumes about 57 – 60% of its gas. The Power Supply Master Plan 2016 (PSMP 2016) and the Gas Sector Master Plan 2017 (GSMP 2017) of Bangladesh have projected shortfall in the demand – supply gaps in short, mid and long-terms. The shortage would increase in case Bangladesh decides to shift its planned coal-based capacity addition to gas-based capacity. The GSMP 2017 has proposed pipeline connectivity with India near Khulna to ease out the constraints in gas supply hydraulics in the short to mid-term. For meeting the long-term demand, GSMP 2017 has also recommended a large diameter 500-km long pipeline from Myanmar to India via Bangladesh. The pipeline would help to balance the hydraulics and avoid laying of additional pipelines to evacuate the LNG Terminals/FSRUs around the Cox Bazaar.

Sri Lanka

Sri Lanka has three sedimentary basins but lacks in any production of gas or oil. At present, 44% of its energy requirement are met by oil. However, it plans to shift from oil to gas. The Sri Lanka government has approved an Energy-mix policy, wherein, two - thirds of electricity generation is to be met by firm energy capacity mix comprising of LNG (30%), Coal (30%), Furnace Oils (15%) and Large Hydro (25%). Accordingly, the Draft 20-year Long Term Generation Expansion Plan (LTGEP) 2020 – 2039 has been drawn with more gas-based capacity. In its 'National Energy Policy & Strategies 2019', natural gas is identified as the fossil fuel of preference to achieve the energy security. A National Policy on Natural Gas (NPNG) has been drafted with an objective to increase gas utilization for economic, social and environmental benefits.

Sri Lanka government's decision in Jan 2020 to go ahead with an LNG plant is evident of its resolve for accelerating the entry of gas /LNG. In August 2020, an agreement has been entered between the Board of Investment of Sri Lanka and Pearl Energy (Saudi Arabia) for a Floating Storage LNG Trading facility at Hambantota port. With this, Sri Lanka aims to reap benefits of fostering regional trade in LNG in South Asia.



Nepal & Bhutan

Nepal and Bhutan do not have any gas reserves or infrastructure. Both countries are rich in hydropower capacity and do not need any gas for power generation. However, petroleum products form a significant component of their energy requirements. This study has explored gas supply options and estimated landed cost of gas / LNG. The 'Small-scale / Virtual LNG Supply' mode emerges as an optimum gas supply mode to begin with. While comparing the estimated specific cost of thermal energy of gas with that of petrol and diesel at prevailing prices, it was observed that there exists a distinct economic benefit for consumers of petrol and diesel to switch to gas in Nepal. In both the countries, substituting non-subsidized LPG by gas is a viable proposition and provides ease and safety in its use. Further, large bulk consumers of diesel could benefit economically by switching to gas. Because of high cost of EVs, a nominal penetration of gas in road transportation is also a possibility. However, the potential for gas consumption is limited due to the low energy needs of these countries.

Launch of Trading Post or Transfer Point

It is interesting that while India would have some surplus LNG receiving capacity after 2023-24 and a significant part of its trunk pipeline network near Bangladesh borders would be ready to receive gas by 2021-22, Bangladesh, on the other hand, faces a supply and transmission crunch to meet the demand for its consumers in the western and northern areas bordering India. It therefore, provides an opportunity in the BBINS region for India and Bangladesh to commence trade in short and mid-term time horizon, from as early as 2022.

The three trunk pipelines under construction on the Indian side which can be considered are: Jagdishpur – Haldia (completion by Dec 2020), Kanai Chata – Shrirampur (Pipeline awarded in July 2019 and completion by 2021) and, Barauni – Guwahati pipeline of GAIL (completion by 2021). On completion of the 'Indradhanush Gas Grid', several cities in India, including Agartala, Silchar, will be in close proximity with Bangladesh on the eastern border with India. The issue is under consideration by Bangladesh for interconnecting their gas pipeline netwok at Satkhira border point, however, an agreement is yet to be inked.

With its geographical location and upcoming pipeline and RLNG infrastructure, India emerges as a potential hub for furthering intra-regional trade akin to a 'Hub and Spoke' supply model. Sri Lanka has also planned a Floating Storage LNG Trading facility at Hambantota port. This will encourage competition in the region.

Gas Hubs, Market and Exchanges

After the initial build-up of pipeline capacity for bilateral trade between India and Bangladesh, the spare capacity available as 'common carrier' would be made available for consumers. The first gas exchange in India has become operational from 20th June 2020 with provision for liquid trade in gas at four physical points of trade and six trading products based on the requirement of consumers. In due course of time, 'exchanges' mushroom for physical and derivative trades. The increase in turnover shall pave way for establishing a possible 'gas price index', which can be used as a marker for trade. With enhanced pipeline connectivity backed up by some LNG storage capacity, addition of multiple suppliers and consumers and increase in trade volumes, the trading nodes have the potential to develop as a 'hub' with standard contracts and mechanisms.

Strategic gains from Inter-Regional Trade

The BBINS region is likely to witness 6-8% growth in GDP in the short to mid-term. India alone is expected to contribute one third of the growth in global energy consumption. However, the BBINS region is short of indigenous/domestic gas reserves and supplies. It is a net importer of gas in the form of LNG. A significant share of the global demand for LNG is likely to emerge from India, Bangladesh and Pakistan. The LNG producing markets are poised to grow and are on the lookout for new consumers. The beginning of trade provides an opportunity for strategic partnership for collective sourcing of LNG at economical prices from the international markets.

Potential for Intra-Regional trade beyond BBINS

While India and Bangladesh are deficient in supply of gas, Myanmar has reserves more than India and has the potential for exports of its surplus production after meeting its domestic consumption and committed pipeline exports to China and Thailand. Besides, Myanmar shares its geographical boundaries with India and Bangladesh in the North-West. The pipeline connectivity with Myanmar would overcome the imbalances, as well as trigger the establishment of a Regional Grid in South Asia. For meeting the long-term demand, GSMP 2017 has also recommended a large diameter 500-km long pipeline from Myanmar to India via Bangladesh.

Expected Benefits in Intra-Regional trade in gas in the BBINS

The potential fiscal benefits for the intra-regional trade in BBINS has been estimated on the basis of the likely trade volumes for the importing and exporting countries. The potential for trade benefits are expected to be about 1.2 Bn $/annum in 2025 and can go upto 1.9 Bn USD/ annum in 2030, and about 3.6 Bn USD / annum by 2040.

Photo - CLEW

Part 1 Gas and LNG: Global environment and perspective for South Asia

Chapter 1: Introduction to Natural Gas & LNG

1.1 Natural Gas

Natural gas is a naturally occurring hydrocarbon gas mixture consisting primarily of methane and some quantities of other higher hydrocarbon gases, moisture, carbon dioxide, nitrogen, hydrogen sulfide and very small amounts of rare gases or helium. Natural gas is a non-renewable hydrocarbon used as a source of energy for heating, cooking, and electricity generation. It is also used as a fuel for vehicles and as a chemical feedstock in the manufacture of plastics and other commercially important organic chemicals. The gas is said to be 'dry', if methane concentration is at least 85%, but it is often found to be more. Wet natural gas contains methane, but also contains liquids such as ethane, propane or butane. The more methane natural gas contains, the dryer it is. Natural gas is odourless and colourless. A chemical called 'Mercaptan' is added to provide odour to facilitate ease in detecting leakages.

Natural gas is found in geological formations inside the mother earth. The most widely accepted theory of its origin is that millions of years ago, the organic matters got buried due to quakes or upheavals on earth's crust. Over a period of thousands of years, more and more sediments, mud and debris piled up on these organic matters. The overbearing layers of mud and sediments applied a lot of pressure and compressed it. Also, the temperature under the earth's crust is very high. The carbon bond of this organic matter breaks down under high pressure and temperature. With high temperature, the organic bonds break into molecules of hydrocarbon gases, and if the temperatures are low, they break down in molecules of hydrocarbon crude oils.

The 'gas' that we fill in our automobiles is gasoline, a liquid distilled from crude oil and not natural gas. Further, the cooking gas supplied in bottles is mainly Propane & Butane. Natural gas comprises more of Methane. Typical composition of Natural gas is as follows:

Table-1.1.1: Typical Composition of Natural Gas		
Methane	CH_4	70-90%
Ethane	C_2H_6	0-20%
Propane	C_3H_8	
Butane	C_4H_{10}	
Carbon Dioxide	CO_2	0-8%
Oxygen	O_2	0-0.2%
Nitrogen	N_2	0-5%
Hydrogen sulphide	H_2S	0-5%
Rare gases	A, He, Ne, Xe	trace

Natural gas occurs in the following natural geological formations:

- Un-associated gas: isolated pockets ,
- Associated gas: gas trapped along with crude
- Tight Gas: Trapped in sub-strata like Shales etc
- Coal bed Methane: pockets within coal seam.
- Hydrates: Methane / Ethane molecules trapped on ocean/sea beds as hydrates

Methane can also be produced by decomposition of organic wastes. This methane is called Bio-gas or Bio-Methane and is similar to Natural gas.

The first discovery of natural gas as a source of heat/combustion was in China in about 500-1000 BC. The ancient Chinese found flames emanating naturally from earth and developed a piped network of hollow bamboos to transport it to short distance for gainful utilization as a fuel. Subsequently, the gas has been found and harnessed across many regions of the world. With the development of sciences for exploration of oil & gas, its extraction & production gained world-wide acceptance for its production as a fuel.

The ease in its combustion made it a preferred fuel option over coal and other crude derivatives, as the latter required refining process to distill / extract oils like kerosene, heavy fuel oils, furnace Oils, diesel and gasoline. The biggest challenge for consumers and suppliers was to create and maintain a pipeline infrastructure. Laying of gas pipelines is an expensive investment and can be gainful for pipelines upto a few hundred miles or so. For consumers at a distance, laying a pipeline did not meet the techno-economic considerations as a fuel substitute. For example, laying a pipeline from the Middle East to consumers in Japan just does not make economic sense, as cheaper fuel options are available.

In terms of specific volumetric heating value, it lagged behind the crude derivatives by 35-40 times at atmospheric pressure. Natural Gas compressed to as high as 200 bar contained only about 45% of the heat value of gasoline per unit volume. The need to realize the economic value of Natural Gas in absence of Trunk pipelines led scientists to explore its liquefaction, cryogenic storage tanks and special carriers.

1.2 Liquefied Natural Gas (LNG)

1.2.1 Liquefaction of Natural Gas

From the seventeenth century onwards, Liquefaction of gases was pursued by scientists. Boyle, Joules, Lord Kelvin and many other scientists played key roles in studying liquefaction of gases. By 1908, all gases including helium were liquefied. Methane was first liquefied in 1886, by condensing it at temperatures below 162 deg centigrade. In 1915, liquefaction of natural gas in the US was carried out on a commercial scale for extraction of helium. Technology for storage of Methane below -162°C was also developed in the 1930s in the United States. LNG at normal atmospheric pressure contains about 60% of the heating value of gasoline per unit volume. The availability of abundant source of natural gas supported by technological advances led to commercial production of LNG near the source of natural gas production and its transportation for consumption at far flung areas.

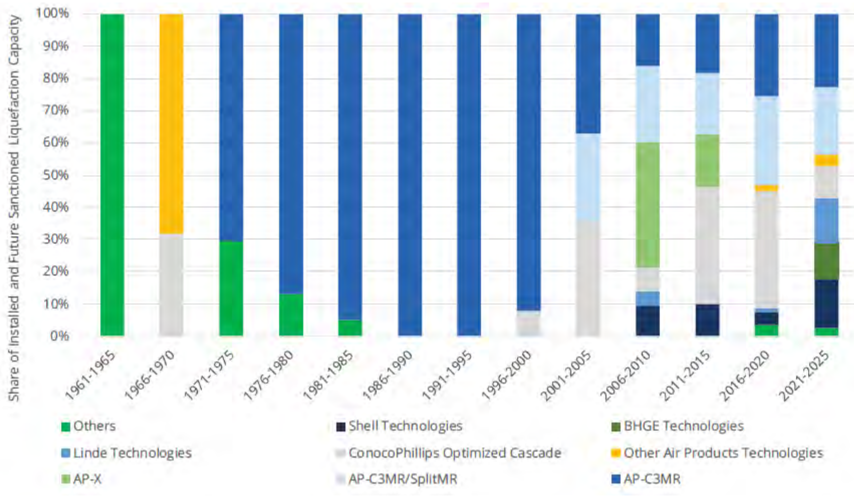
Liquefaction Process of NG involves removal of dust, acid gases, helium, water, and heavy hydrocarbons from the naturally explored gas and then condensing it into liquid by freezing it to below approx -162°C. The maximum transportation pressure is set around 25 kPa.

The first commercial Liquefaction and storage plant was commissioned in 1940 by the East Ohio Gas Company at Cleveland, Ohio for storing LNG and re-gasifying it for the peak winter demands. By 1942, the storage facility had four large cryogenic vessels for storing LNG for meeting the winter demand. In 1944, leakage of LNG from a tank led to a major explosion which claimed nearly 130 lives, and the facility was closed down. The accident led to a thorough review of the practices for safe storage and handling of LNG.

The NG Liquefaction Technology

There are two popular methods for commercial liquefaction. The first method uses a refrigerant to cool the natural gas in stages and is referred as 'cascade method'. The second method is based on the 'Joule-Thomson effect' that a compressed gas cools when expanded through an orifice. Both the methods are in use for commercial liquefaction of natural gas. Most of the Liquefaction companies have developed their own customised liquefaction processes. The popular ones are Air Products' liquefaction technologies (namely AP-C3MR, AP-X, AP-N), which has a 59% share in the global installations for liquefaction of natural gas. Conoco Philip's Optimized Cascade Process is the next most popular technology followed by proprietary processes of Shell, Linde and others. The compressors were initially powered by Steam Turbines, but have given way to Gas Turbines. Based on the techno-economic considerations, these technologies can be customised for a wide range capacity. Each liquefaction process unit is called a 'train'. A Liquefaction facility selects one or multiple 'trains' of suitable capacity / size. Over the years, for optimizing costs / achieving economies of scale, individual train capacity has gone up to 8 MTPA.

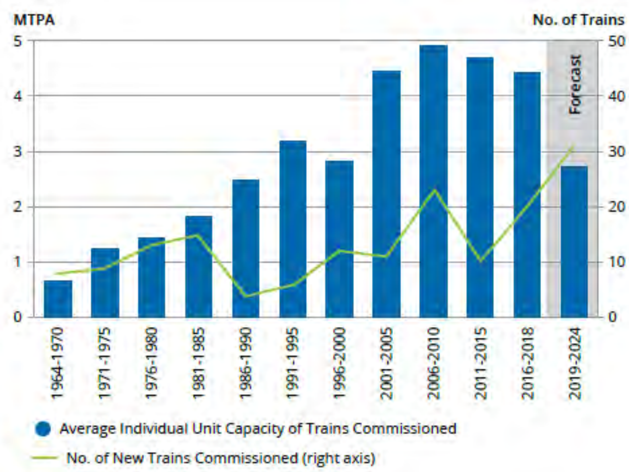
Fig-1.2.1: Share of Commissioned and Start-up Liquefaction Capacity by Technology and Start-up year



(Source IGU World LNG Report 2020 / Rystad Energy)

The growth in average train capacity and population over the years are mapped in the Graph below:

Fig-1.2.2: Number of Trains Commissioned and the Average Train Size (1964 – 2024)



(Source: IGU World LNG Report 2019 / IHS Markit)

1.2.2 LNG Transportation by Ocean Going Vessels (OGV) & Terminals

The accident at Cleveland LNG facility stepped up research in low temperature alloys, insulation materials as also review of safety in handling and storage of LNG. In 1958, backed by funding from the British Gas Council, a used WW-II cargo ship was converted as an LNG Vessel, the 'Methane Pioneer', by Alabama Drydock and Shipbuilding Company, Alabama USA. The project was operated by a Joint Venture company formed as a partnership between Conoco and Union Stock Yards, and was later joined by Shell. In Jan 1959, the first voyage by 'Methane Pioneer', set sail from the Calcasieu River facility, Louisiana US for Canvey Island in England, carrying the first ever shipment of about 32,000 barrels of LNG and completed the voyage in 27 days. This laid the foundation for customised ship-building for transporting LNG. Meanwhile, the monetisation of a large discovery of NG reserves in Algeria in early 60s, catalysed commercial manufacturing of LNG facilities, Ship-building and Regasification terminals in Britain, France & Spain. In 1964, the world's first purpose-built LNG carrier, the 'SS Methane Princess' manufactured for the British Gas by Vickers shipyard entered service for supplying LNG from Algeria to England.

Throughout the decades of 60-70s, the United States, which already had sizeable gas reserves and pipeline infrastructure for domestic and commercial consumers, restarted its LNG industry with a series of Liquefaction and Re-gasification plants for meeting the peak demand periods as well as supplying gas as LNG to distant states/cities not connected with trunk pipelines. A number of LNG import facilities were built on the East coast of the USA to import LNG as and when required, mostly for winter peak shaving. Subsequently, many gas producing countries like Indonesia, Brunei, Malaysia, Qatar started producing LNG. After the shale gas boom post 2010-11, US gas production and supplies ramped up, surpassing the domestic demand. This led to many of these facilities being converted to LNG export terminals. Besides, significant new LNG export facilities have been set up and have been envisaged to come up in future.

Chapter 2: Development of LNG Facility: Issues & Challenges

An LNG Liquefaction facility is a multi-billion dollar investment. As per a report by Oxford Institute of Energy Studies, the data of about 50 LNG projects analysed by EY in 2014 indicated that the capital outlay for an average LNG liquefaction project size, worked out to about $10-11 Billion. Besides it is usual for a greenfield project, where no prior construction infrastructure or utilities are available, to take 8-10 years from the conceiving of project to delivery of the first cargo.

The Liquefaction capacity growth depends on the following key factors:

- The availability of cheap gas and in sufficient quantity and identification of location with sea port infrastructure.
- Availability of substitutes and their price in target markets.
- Identify buyers and ink Long-term SPA (contract) with them on an assured off-take (Take-or-Pay) quantities.
- Financial commitment based on a healthy IRR for CAPEX and OPEX of Liquefaction facility including Shipping.

2.1 Primary requisite: Availability of natural gas

a) Global Gas Reserves

Supported by development of technologies for exploration and a capable pool of service providers, significant new discoveries of gas reserves have been made across all the global basins. The availability of surplus gas, well supported by increase in prices of crude, a strong substitute, and reduction in the costs of plant and shipping due to technology advancements & economies of scale, were key enablers for the growth of LNG capacity.

Russia followed by Iran and Qatar are globally accepted as nations with very high 'Proven reserves' of gas. Countries producing Natural Gas first use it for their heating / economical value and the surplus is exported to other countries by pipelines or as LNG. It also occurs that in some areas the reserves are such located that laying a pipeline is an onerous task. In such scenarios, countries prefer to convert the gas into LNG and then sell it or utilize it to their benefit.

In the 70s, backed by huge discoveries and the demand for gas by Japan, new Liquefaction facilities were installed in Brunei, Abu Dhabi and Indonesia. In the 80s, the discoveries led to new liquefaction facilities in Malaysia and Australia, in addition to brownfield expansions in Algeria and Indonesia. The next two decades witnessed the impact of new discoveries and lower CAPEX / OPEX of LNG facilities, Shipping, etc. to spur steady growth. The 1990-2000 decade saw Qatar, UAE, Nigeria and Trinidad & Tobago discover gas reserves in large quantities and they installed liquefaction capacities for exports. In the first decade of this millennium, Egypt, Yemen, Russia, Oman and Norway also joined as LNG producers.

A list of countries with 'Proven' gas reserves along with their annual production of Gas / export of LNG is as below:

Table-2.1.1: Global Gas Reserves, Production and LNG Exports

Sl No	Country	Proven Reserves	Production in 2018	
		Trillion Cubic Metres (TCM)	Billion Cubic Metres (BCM)	LNG Export (in MTPA)
1	Russia	38.9	670	19
2	Iran	31.9	240	
3	Qatar	24.7	175	79
4	Turkmenistan	19.5	61	
5	USA	11.9	831	23
6	Venezuela	6.3	33	
7	China	6.1	161	
8	S Arabia	5.9	112	
10	UAE	5.9	64	6
11	Nigeria	5.3	49	21
12	Algeria	4.3	92	10
13	Iraq	3.6	13	
14	Indonesia	2.8	73	15
15	Australia	2.4	130	69
16	Malaysia	2.3	72	24
17	Europe (Excl Norway & CIS	2.3	130	
18	Egypt	2.1	58	2
19	Azerbaijan	2.1	18	
20	Kazakhstan	2.1	24	
21	Canada	1.9	184	
22	Kuwait	1.7	17	
23	Norway	1.6	120	5
24	India	1.3	27	
25	Oman	0.7	36	10.5
26	Peru	0.4	13	4
27	Trinidad & Tobago	0.3	34	12.5
28	Papua New Guinea	0.2	5	7
29	Cameroon	0.1	5	1
30	Eq Guinea	0.1	6	4
31	Yemen	0.1	3	Refer Footnotes
32	Angola	0.1	6	4
World		**196.5**	**3867**	**316**

(Source: BP Statistical Review, IGU, Others)

Notes:
1. Countries exporting LNG or with reserves of more than 1 TCM have been concide rd.
2. Yemen's LNG capacity of 6.7 MTPA is shutdown since 2015 due to local security concerns.
3. Actual reserves may be more.
4. Production of LNG.

It can be seen that gas reserves in many countries are less than 1 TCM but they have been found economical for LNG liquefaction and export.

2.2 Availability of market

The crude prices, albeit for brief periods of volatility, saw stable and increasing trend from 1980s to 2015. The 5-year moving average was upwards of 20 USD/bbl in the eighties and nineties, and rising sharply thereafter to breach 100 USD/bbl by 2015 before sliding down to around 50-54 USD /bbl by 2019 and to levels of $ 40- 45 /bbl as in July- Aug 2020 post economic slowdown post- COVID 19

As natural gas was targeted as a substitute for crude oil and refined products, its pricing was kept at a discount in terms of the heating value in crude and its derivatives. The target markets were those which were importing fuels like coal and crude / refined oils. The key requisites for the recipient consumers were a LNG Receiving & Vaporization terminal and a gas pipeline / transportation infrastructure.

United Kingdom, France, Japan, Korea and other European countries were amongst those countries to install LNG terminals and promote trade. United States, also an initial consumer, used LNG to supply gas to its far flung areas, not connected with gas pipelines and for winter peak shaving.

Technology and cost of Liquefaction & Shipping

This is the most complex element as it has many variables specific to locations including Greenfield or Brownfield expansion, availability of utilities, the composition of gas, , recovery of Sulphur, LPG and Mercury, Carbondioxide treatment and sequestration. Average cost of plant per ton of LNG is an indicator of costs.

Over the years, improvements in liquefaction technology, design optimization along with economies of scale in production of LNG trains and efficient project execution have led to reduction in the capital costs per tons per annum (tpa). .As per an OIES Research (Paper NG- As per an OIES research paper – 142 (Outlook for Competitive LNG Supply – March 2019), the 5 year moving average cost of LNG plants for the period 2012-2017 have reduced to 941 $/tpa from 1,874 $ / tpa during the period 2003 to 2012 based on the data collected from industry sources. The study has also analysed the complexities faced at different geographical locations, which affected the capital cost outlay. During this period, Qatar and the new USA LNG plants (lower 48) have lowest capital costs at 480 & 660 $/tpa. The West Africa LNG plants come next with capital cost of about 1,084 $/tpa, followed by Russia at 1,292 $/tpa. The capital costs of Australian LNG plants varied from 1,273 – 1,789 $/tpa. The FLNG plants cost about 1,432 $/tpa. FLNG 'Prelude' faced severe challenges in project execution and the cost over-runs attributed to its high capital cost of 1,975 $/tpa.

Shipyards in Japan & Korea also developed capabilities and technologies for manufacturing of LNG Carriers. The ensuing competition brought down the acquisition costs for vessels/LNG Carriers. The containment capacity of Carriers also increased abetting to availability of LNG Carriers at lower prices. The average cost of vessels for a LNG vessel of capacity 180,000 cubic metres (cm) is around 180 to 190 Mn USD for ME-GI (M-type Electronically controlled Gas Injection) or X-DF (Two-stroke dual fuel) type propulsion technology. The long-term charter cost will depend on CAPEX and at present are about 70,000 $/day.

Liquefaction technology and Shipping costs have been separately covered later in this report.

2.3 Key stakeholders & scale of investment

The key stakeholders in an LNG project are:

- Gas Suppliers: Gas Producers who commit supplies and Transporters/Pipeline owners.
- Buyers: End users, Traders or Portfolio Players.
- Developer: Deploys teams for Feasibility studies, Marketing, Business Development, Engineering teams for Front End Engineering Design (FEED) & Project Finance. He is also responsible for ensuring Shipping and time charters and hiring an EPC contractor.
- EPC contractor: Carries out all the construction activities of plant and port/berthing.
- Ship Charter company: It plans and orders LNG vessels and maintains the fleet.

The CAPEX requirement for a 'Greenfield' LNG capacity comprises of investments for the following:

a. **Gas supplies:** This includes the cost of developing a gas reserve and the associated pipelines for its transportation. This can vary across geographical markets and depends on the average price of production and connecting pipeline costs. The global benchmarks are between 2 to 3.5 $/mmbtu. Alternately, gas supplies can be contracted from a major supplier and a pipeline connectivity is planned.

b. **Liquefaction plant:** This is the most cost intensive and complex element of supply chain. As discussed earlier, the cost varies for Greenfield and Brownfield development as also on the availability of enabling infrastructure (proximity to gas supply pipelines, ports, electricity, manpower etc) and the geographical conditions. In terms of levelised costs of gas, this can translate from 2 to 4.5 $/mmbtu.

c. **Shipping:** The costs depends on the capacity and size of a suitable fleet of LNG vessels. The average cost of vessels for a LNG vessel of capacity 180,000 cubic metres (cm) is around 180 to 190 Mn USD for state-of-the-art propulsion technology. The long-term charter cost will depend on CAPEX and at present are about 70,000 $/day. The bunker fuel costs depend upon distance and the route of the voyage.

CAPEX for Greenfield LNG

CAPEX requirement for a 'Greenfield' LNG capacity investment can be appreciated by an analysis of the financial data of LNG Canada, a greenfield facilty of 14 MTPA, coming up in Western Canada by an OIES research paper NG 142 (LNG Outlook For Competitive LNG Supply–March 2019) . As per the report, the project comprises gas reserve development in the resources of Montney area, a pipeline connecting the gas reserves to the port of Kitimat, British Columbia, and a Liquefaction Plant initially of 14 MTPA with provision for future brownfield expansion. The FID presentation provided some indicative prices of LNG ('Delivery at Terminal' price). Break-up of The CAPEX is to the tune of $31.2 Bn as under:

- Upstream development of Gas Reserves: 12.4 Bn USD
- Pipeline from gas fields to Liquefaction facility: 4.8 Bn USD
- Liquefaction Plant: 14 Bn USD

To mobilise finances and certainty of off-take, the project developers roped in the Buyers who are Oil & Gas portfolio players from UK, China, Malaysia, Japan and Korea to participate in the equity. The lead partner, Royal Dutch Shell holds about 40% equity and the rest is from Petronas Malaysia (25%), PetroChina (15%), Mitsubishi Corp (15%) and Korea Gas (5%). As per the research paper, the break-up of the target price (DAT JKTC) alongwith its share in total cost is estimated as follows:

Upstream cost of lean unconventional gas supply	$8.50/mmBtu	100%
Tariff on 670km of 48" gas pipeline:	$8.50/mmBtu	100%
Into LNG plant gas supply price:	$8.50/mmBtu	100%
Liquefaction Cost (14 Mtpa @ $1,000/tpa):	$8.50/mmBtu	100%
LNG shipping W canada/Kitimar to JKTC:	$8.50/mmBtu	100%
Gross Margin:	$8.50/mmBtu	100%
DAT JKTC:	$8.50/mmBtu	100%

The Financial Investment Decision (FID) was approved in Oct 2018. Project will commence delivery of cargoes in 2023.

2.4 Implementing LNG Capacity: Financing & EPC

In view of the capital intensive nature, it is apparent that a detailed analysis of risks, its mitigation measures are carried out and a business model with a healthy IRR is developed before the 'Final Investment Decision' (FID) is arrived upon. The project cycle can be divided between Pre-FID & Post-FID activities.

(a) Pre-FID activites: The key activities are:

- Feasibility studies: Availabilty of adequate gas supplies on a sustained basis is the first and foremost requirement. As a thumb rule, at least 1 tcf of reserves are required for 1 MTPA plant for 20 years' supplies. The studies also include identification of sites and adjoining port. The feasibility also addresses all local issues (land, local laws, regulations, permits & licence, free access) and serve as a broad reference for the Pre 'Front End Engineering Design' (FEED).
- Pre-FEED studies: It is undertaken to address technical issues like connecting pipelines, plant capacity, configuration, efficiency, benchmark EPC costs for the plant, port, logistics, shipping etc., which are firmed up in FEED stage.
- Marketing: To firm up buyers (End users, Portfolio players, Traders, Shareholders). Key issues like Take-or-Pay, operational / commericial flexibilities, price indexation, dispute resolution mechanism are discussed and a Letter of Intent (LoI) followed by an Heads of Agreement (HoA) is signed with the Buyers. After final FEED data is available, a negotiated Sale Purchase Agreement (SPA) with Buyers is finalized,.
- FEED (Front End Engineering Design): Complete engineering for project's technical specifications and cost estimates, Finalize the tender documents for the EPC contracts or packages, invite bids and complete all the pre-award discussions. Also finalize the pre-order stage for all long-lead materials / equipments, Long-term ship charter agreements or orders on shipyards.
- Finance & Decision making (Financial Investment Decision or FID): Due-diligence is carried out for all contracts, viz, SPA, EPC Contracts and Ship Charters. The structuring of Project Finance model is finalized. Based on the costs and revenues, the IRR is worked out. The reports are reviewed by decision making bodies and FID is accepted or deferred for more data, risk analysis and mitigations etc. Along with the FID, main orders for equipments, EPC, Shipping, Port Infrastructure etc. are also approved by the Functional Committees / the Government / the Company Board / Shareholders as per the prevailing statutory regulations / policies.

(b) Post-FID activities

The key post-FID activities are award of all the contracts, (i.e., EPC, Long lead equipments, Ship charters / Acquisition) Construction, Cash flows, HSE, Manpower and other operational issues. In a study on risks in LNG projects, it has been seen that 13 of the 20 large-sized LNG projects faced cost and time overruns. The key attributes are project execution issues, accounting for nearly two-thirds of the delays, the rest are due to Management delays in decision making and unforeseen environment/ government/ local interferences and issues. The delays in an LNG project can upset the IRR in the long run.

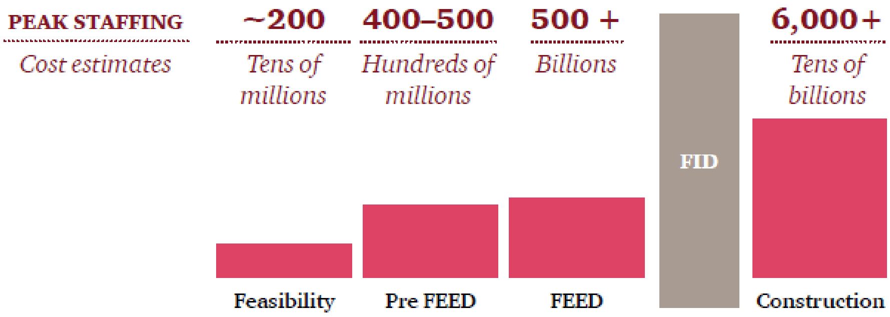
The Pre-FID and the Post-FID activities in case of Greenfield projects take about the same time of 4-5 years.. The Pre FEED & FEED alone takes about two years by a team of about 500 professionals. The marketing activities are intertwined with FEED for all the input numbers as regards throughput and costs. Marketing takes about 4 years before SPAs are agreed upon and executed. The project execution can take upto 5 years in case of Greenfield project where construction infrastructure is to be established. As per a PWC (PricewaterhouseCoopers) 2014 paper,'The progression of an LNG project' prepared for LNG projects in Canada, the broad timelines for key project activities are as follows:

Fig-2.4.1:Timelines for an LNG project

(Source: PWC)

The prospective LNG producers invest a substantial manpower resources in several specialized areas for the Pre-FID. As per the abovementioned study by PWC, cost of staffing even for Pre-FID activities can consume billions of dollars as explained in the figure below:

Fig-2.4.2: Investment inflows for an LNG project



(Source: PWC)

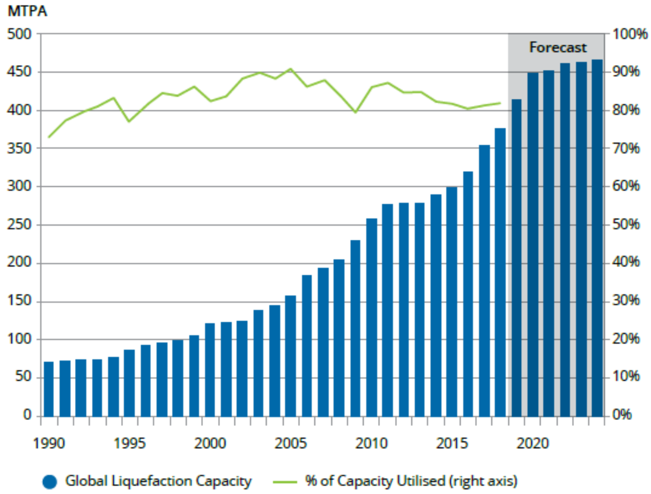
The complexities of the Pre-FID activities and a thorough due diligence of all contracts, risks etc prior to arriving and approving the FID is a commitment from all stakeholders to realize the LNG project.

Chapter 3: LNG: Liquefaction Capacities

3.1 Global LNG Capacities and Utilization

As per IGU Global LNG Report 2019 and 2020, the growth in global capacity addition was around 7% in 2016, 2017 and 2018 and 11% in 2019. A capacity of 42.5 MTPA was added in 2019. The global liquefaction capacity stood at 430.5 MTPA at the end of 2019 with average utilization of 81.4%. The growth of from 1990 to projected in 2025 is as follows:

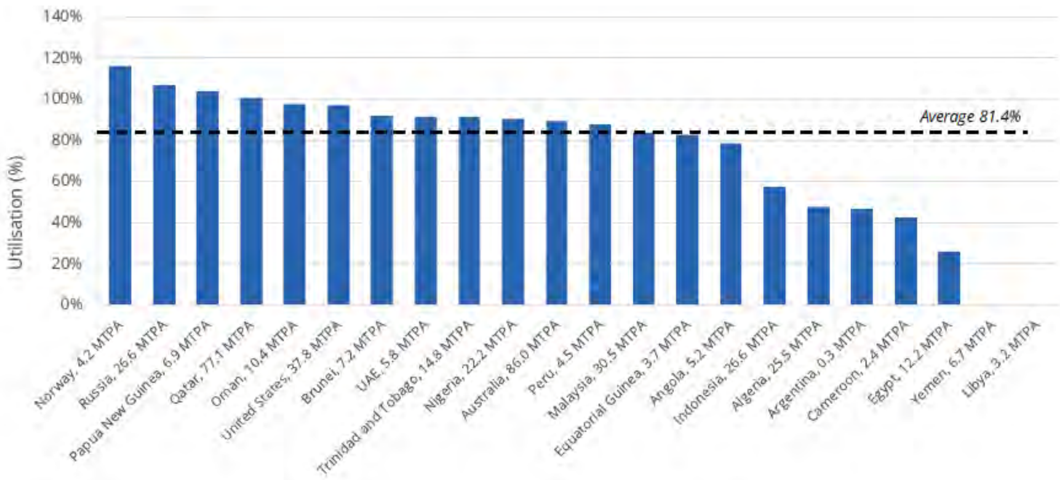
Fig-3.1.1: Growth of Global LNG Capacity over the year from 1990 to 2025 (projected)



(Source: IGU World LNG Report 2019 / IHS Markit)

A significant aspect of the LNG Liquefaction plants is the high level of capacity utilization across most of the plants as seen in the figure below:

Fig-3.1.2: Country-wise LNG Capacity and utilization



(Source: IGU World LNG Report 2020 / Rystad Energy)

3.2 LNG capacity under construction & FID achieved in 2019

3.2.1 Under Construction capacity:

The IGU 2019 report indicated that LNG capacity of 101.3 MTPA was under construction. As regards the ongoing projects, More than 75% of this capacity addition shall be contributed by Liquefaction plants in the North America, with LNG Canada the only non-US LNG project.

3.2.2 FID achieved in 2019:

After record FIDs in 2014 & 2015, FID in 2016 & 17 came down to a mere capacity of 13.3 MTPA. There was an improvement in 2018 and FID for a capacity of 21.5 was achieved. The FIDs in 2019 reached a record 70.6 MTPA, which is 40% higher than the highest ever annual FID for 50.4 MTPA achieved in 2005. Out of this, 43 MTPA have been committed without long-term contracts. The FIDs and LNG project start-up details for the year 2019 as per industry sources are as follows:

Table- 3.2.1: Final Investment Decision for LNG Capacities achieved in 2019

Month	Project	Country	Capacity (in MTPA)	Promoters
Feb-19	Golden Pass	USA	15.6	Qatar Petroleum (70%) and ExxonMobil (30%)
Jun-19	Mozambique LNG	Mozambique	12.9	Total
Jun-19	Sabine Pass	USA	4.7	Cheniere
Aug-19	Calcasieu Pass	USA	10	Venture Global
Sep-19	Arctic LNG -2	Russia	19.8	Novatek
Dec-19	Nigeria LNG Train -6	Nigeria	7.6	Nigeria National Petroleum Corp., Shell & Total
Total Capacity			**70.6**	

3.3. LNG capacity in Pre-FID stage

As per IGU's World LNG Report 2020, backed by gas reserves, a capacity of about 907.4 MTPA is in the Pre-FID stage, mainly in the following countries:

- USA - 350.5 MTPA
- Canada - 221.8 MTPA
- Austraia - 50 MTPA
- Qatar - 49 MTPA
- Russia - 42.2 MTPA

The uncertainty of demand or lack of assured buy-outs is holding up the global capacity build-up in near to short term. Many of the LNG producers are exploring the affiliate marketing model to accelerate their FIDs and project development. In 2018, LNG Canada & Greater Tortue FLNG achieved their FIDs utilizing a new marketing model which offers participation in project equity / Capex by Buyers. These 'affiliate marketing' models mitigate the risk of CAPEX and OPEX for the developer and facilitate FID to the satisfaction of all key stakeholders including shareholders, financers and the government. The model is gaining popularity in North America and other cost-intensive projects.

3.4 Key countries engaged with building LNG Capacity

A) USA: Buoyed by the shale gas boom, USA chalked out large-scale plans for gas exports gas as LNG. The FTA restrictions on LNG exports were suitably relaxed and necessary approvals were obtained for LNG export terminals from FERC. Several LNG plants were taken up. Within three years from commencement of LNG exports in Dec 2019, USA had achieved a capacity of 7.45 bcfd, which is about 58 MTPA. As of Jan 2019, nearly 77.4 MTPA, or over 75% of the global capacity of 101.3 MTPA was under construction is in the North America. Out of this, LNG Canada is the only non-US project. In view of scale of capacity build-up and its emergence as the largest LNG exporter by 2023, the author has specifically analysed USA's build-up, the existing, under construction and the approved capacities awaiting FID have been examined in detail as under:

(i) USA: ExistingExport Terminals: As per FERC, as in Dec 2019, LNG export commercial capacity was 7.45 BCFD (about 56 MTPA) across 7 Export terminals as follows:

Table-3.4.1: FERC approved Commercial Capacity as in Dec 2019

Sl No	Project	Capacity (in Bcfd)	Description
1	Kenai LNG AK	0.2	Trans Foreland
2	Sabine Pass LA	3.5	Cheniere, Trains 1 – 5
3	Cove Point MD	0.82	Dominion Cove Point
4	Corpus Christi TX	1.44	Cheniere Corpus Christi LNG Trains 1&2
5	Hackberry LA	0.71	Sempra- Cameron LNG Train 1
6	Elba Island GA	0.07	Southern LNG Units 1 & 3
7	Freeport TX	0.71	Freeport LNG Expn / FLNG Train1
Total		**7.45**	

(ii) USA: Capacity with FIDs and under construction

As in May 2020, the FERC- approved capacity, which has achieved FID and have proceeded with construction in the US, is about 9.78 Bcfd or approx 77 MTPA as follows:

Sl No	Project	Capacity (in Bcfd)	Description
1	Hackberry LA	0.71	Sempra- Cameron Train 3
2	Corpus Christi TX	0.72	Cheniere Corpus Christi Train 2
3	Sabine Pass LA	0.7	Sabine Pass Liquefaction
4	Elba Island GA	0.14	Southern LNG Trains 7-10
5	Cameron Parish LA	1.41	Venture Global Calcacieu Pass
6	Sabine Pass TX	2.1	Golden Pass Trains 1,2,3
7	Calcasieu Parish LA	4	Driftwood LNG
	Total	**9.78**	

(iii) USA: Capacities under Pre-FID with FERC approval

About 22.922 bcfd (about 182 MTPA) Liquefaction capacity is approved by FERC as in May 2020, and is in Pre-FID stage. The construction is yet to commence. Project wise these capacities are mapped in the table below:

Sl No	Project	Capacity (in Bcfd)	Description
1	Lake Charles LA	2.2	Lake Charles LNG
2	Lake Charles LA	1.08	Magnolia LNG
3	Hackberry LA	1.41	Sempra- Cameron Train 4 & 5
4	Port Arthur TX	1.86	Port Arthur LNG Trains 1 & 2
5	Freeport TX	0.72	Freeport LNG Train 4
6	Pascogoula MS	1.5	Gulf LNG Liquefaction
7	Jacksonville FL	0.132	Eagle LNG
8	Plaquemines Parish LA	3.4	Venture Global LNG
9	Brownsville TX	0.55	Texas LNG
10	Brownsville TX	3.6	Rio Grande LNG
11	Brownsville TX	0.9	Annova LNG
12	Corpus Christi TX	1.86	Cheniere Corpus Christi LNG
13	Sabine Pass LA		Sabine Pass Liquefaction
14	Coos Bay OR	1.08	Jordan Cove
15	Nikiski AK	2.63	Alaska Gasline
	Total	**22.922**	

B) Canada: Canada is the fifth largest producer and the fourth largest exporter of Natural Gas. It is a part of the fully integrated natural gas market of North American continent. It has an import terminal at St John, New Brunswick. It has one LNG Export terminal under construction in British Columbia. The first export terminal, under construction at Kitimat BC, will source gas from Montney formations near Dawson Creek, BC. At present two trains totalling 14 MTPA are under construction. The project achieved its FID via the 'Affiliate Marketing' model. Royal Dutch Shell Plc UK is the lead partner (40%) along with Petronas Malaysia (25%), PetroChina (15%), Mitsubishi Corp Japan (15%) and Korea Gas Corporation, South Korea (5%).

Canada has plans to export at least 30 MTPA from British Columbia by 2030. However, of late its LNG projects are facing multiple issues like acquiring indigenous land rights, environmental assessment, 'Greenfield versus brownfield' dilemma, and lack of firm policies owing to frequent change in governments. As per industry sources, except for the Woodfibre LNG, other projects are unlikely to achieve the FIDs in near future.

C) Australia: With the commissioning of Ichthys LNG T-1&2 and Prelude LNG, Australia has overtaken Qatar as the nation with the largest nameplate liquefaction capacity reaching 87.6 MTPA.

D) Qatar: With a capacity of 77 MTPA, Qatar till 2019 remained the country with the largest liquefaction capacity. Qatar had imposed a moratorium on the North Fields, which has been lifted in 2017 and immediately thereafter, it planned to increase in LNG capacity to 110 MTPA.

In 2018, it announced FEED for 4 Mega trains of 7.8 MTPA each. In 2019, with the discovery of 17.60 tcf in the North Field, it upgraded its plans to increase its capacity to 126 MTPA by 2027. It had planned to achieve FID in 2020, but it could get delayed till a year or two due the global slowdown following the COVID 19 outbreak.

E) Russia: In 2018, Russia successfully commissioned Yamal LNG, thereby commercializing its stranded Arctic gas assets. Russia exported 29.3 MMT in 2019. The largest proposed LNG project, The 3-Train Arctic LNG-2 (Total 19.8 MTPA) achieved its FID in September 2019.

Amongst its proposed LNG terminals are an additional 5.2 MTPA at Sakhalin-2. It also plans a Far East LNG terminal of 6.2 MTPA and another 10 MTPA at its Baltic Sea operations .The OIES research paper, NG 154 –Nov 2019 (Russian LNG: Becoming a global force) has reviewed the gas environment including reserves and potential (in terms of capabilities, infrastructure for LNG production and enabling policies). By 2030, Russia has potential to reach a capacity of 100 MTPA and join Qatar, Australia and USA in the top four LNG Exporting countries.

F) Indonesia: Construction of Train 3 at the Tangguh project (3.8 MTPA) is progressing well and is likely to gey commissioned in 2021. The Abadi LNG (9.5 MTPA) has been approved and is awaiting FID in 2021.

G) Mozambique: It is expected to become one of the large exporter of LNG. A capacity of 3.4 MTPA is under construction. The 12.9 MTPA capacity LNG plant in Area 1, now being developed by Total, achieved its FID in Sep 2019. The Rovumma LNG, being developed by ExxonMobil with ENI in the adjacent Area-4, has received an Initial Investment Decision of 500 Mn USD. It is expected to achieve FID in 2020.

H) Papua New Guinea: The country exported 8.5 MMT in 2019. The FID for the three-train of PNG Expansion is expected in late 2020 or in 2021. The country has a Pre-FID capacity of 12 MTPA.

3.5 Floating Liquefaction (FLNG) Capacities

Evolution of Floating LNG

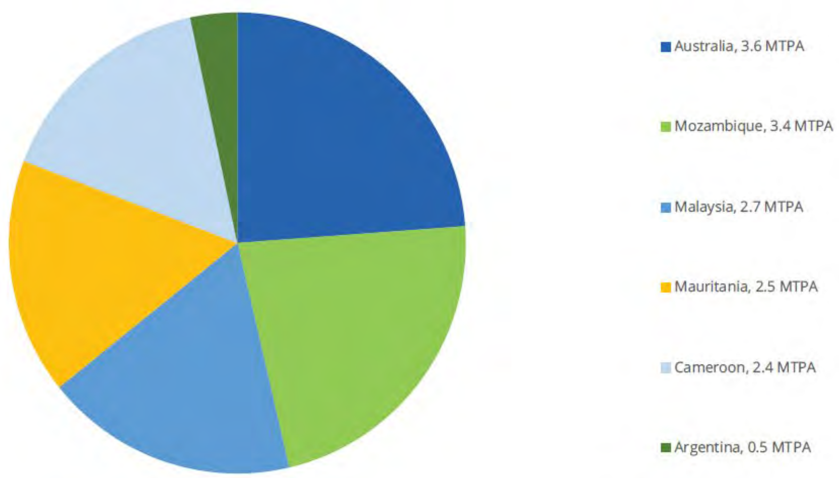
Liquefaction plants are suitable for off-shore gas fields, for which laying a pipeline is expensive or for stranded reservoir with sub-economic capacity for installing a Liquefaction terminal. It can be also used for monetising on-shore reserves by connecting them with a pipeline. The concept of constructing an LNG plant off-shore has been studied by the LNG industry for several decades. However, the industry adopted a very conservative and cautious approach to build these plants. The CAPEX per MT capacity for a FLNG is much higher than a conventional LNG facility. The benefits are that the liquefaction capacity can be suitably customised for commercially monetizing the associated gas fields. Above all, as FLNG facility can be relocated and towed to a new location if required, it has 'capital mobility' unlike the 'sunk cost' nature of an LNG Terminal.

3.5.1 Existing FLNG Plants and Capacity under construction

Between 2011 and 2014, four Floating Liquefaction plants, Shell's Prelude LNG (3.6 MTPA), Petronas's PFLNG1 (1.2 MTPA at Satu) & PFLNG 2 (1.6 MTPA at Rotan), ExmarCarribean FLNG, later relocated to Argentina as Tango FLNG (0.5 MTPA), and Cameroon's Kribi FLNG (1.2MTPA) were the series of first Floating LNG which were awarded. All but PFLNG 2 (Rotan) have been commissioned. Rotan is expected to be commissioned in 2021.

The ability of FLNG to relocate has been again successfully demonstrated at Petronas's PFLNG Satu, which was relocated in Jan 2019 to Kebabangan Fields and produced its first LNG cargo in May 2019. As per IGU's World LNG Report 2020, three FLNGs are under construction, Petronas's Rotan (1.5 MTPA), ENI-lead Coral South FLNG (3.4 MTPA) for Rovuma Basin Area 5 (Mozambique) and TortueAhmeyin FLNG (also known as GolarGimi) also of 3.4 MTPA capacity. The Coral South FLNG in Rovuma basin, Mozambique shall be the first FLNG for Ultra-deep site of nearly 2000 metres depth. As per the report, about 15.1 MTPA of Floating LNG is operational or under construction across the globe as shown in the figure below:

Fig-3.5.1: Operational and Sanctioned FLNG Capacity (Source: IGU World LNG Report 2020 / Rystad Energy)



3.5.2 Future of FLNG

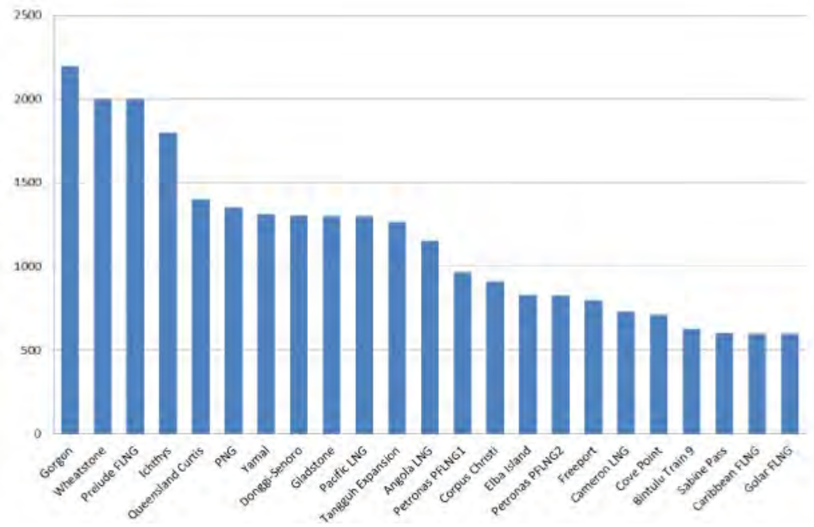
Third-party leasing and tolling of FLNG help the owners of gas reserves to shorten the timeframe for monetizing their assets. The conversion of old LNG Carriers has aided in provided commercial feasibility of more number of FLNG projects. Golar and Exmar are offering their FLNG on charter or tolling basis along with its operations. Some recent industry trends indicate that capital ownership structure is being preferred to leasing or tolling.

To sum up, the key factors in favour of FLNG are:

- Suitable for marginal or stranded fields.
- Can be deployed for shallow or deep off-shore gas fields
- CAPEX is generally higher than land-based terminals. However, CAPEX can be lowered by utilizing old LNG vessels of matching capacity. .
- Ideal for locations where there is a lack of availability of skilled manpower, other construction infrastructure or local social issues, which can delay the installation period for a land-based terminal.

The key constraints in installing FLNG are the weather restrictions which can delay berthing of vessels and a higher OPEX due to cost of transporting manpower, spares and maintenance. The other key constraint is the size. The largest FLNG, i.e., Prelude with a capacity of 3.6 MTPA is built on a vessel that is 488 m long, 74 m wide and displaces nearly five times more than a world class aircraft carrier. In 2014, Shell had estimated about USD 11 billion for the project but the project cost overruns resulted in an approximate project expenditure of about 15 Billions. The perceived project risks are much higher and therefore FLNG is considered a 'niche' installation. The large liquefaction installations prefer the conventional terminals. So, while a capacity of about 119.2 MTPA are in Pre-FID stage, it remains to be seen how much of it secures FID in the coming years.

Fig-3.5.2: Liquefaction Plant's CAPEX in USD / ton



(Source: OIES)(Source: Compiled for OIES by Brian Songhurst& Claudio Steur from GIIGNL, Reuters, OGJ, IGU, PR Newswire & companies' websites)

Chapter 4: LNG Shipping

4.1 Characteristics of LNG Shipping

As the LNG is produced and stored at or below (-)162 °C at atmospheric pressure, it requires cryogenic technology for its storage and handling at loading and unloading end. Its shipment too requires special cryogenic vessels, capable of ensuring that the LNG remains as liquid and there is minimal 'boil-off' during the voyage. The manufacturing of LNG vessels needs special technology and they are expensive as compared to the oil tankers. While a very large oil tanker (VLCC) can be bought for 90-100 Mn USD, the costs of LNG vessels are in the range of 180-230 Mn USD.

Some other characteristics of LNG shipping are as follows:

- **Customised Specifications:** For Long-term LNG contracts, the ports for loading / unloading along with the maritime route for navigation and draft available at the ports of call are known in advance. Accordingly, the technical specifications for vessels were very specific and customised.
- **Limited Deployment:** The long-term trade between a seller and buyer leave little room for their deployment for laden / ballast voyage for other locations.
- **Limited fleet:** The LNG trade volumes are several times less than crude with strict 'Take-or-pay' clause for about 90% of the contracted quantity. Global fleet size is limited as per the LNG Liquefaction capacities and trade volumes.
- **Limited secondary market for sale-purchase:** It had not been possible to establish the assessment of the 'residual value' of LNG vessels as very few vessels are available for second-hand trade. This is unlike for normal oil tankers, which can be easily resold in the secondary markets. In absence of a standard valuation method, borrowing for second-hand vessel is constrained as bankers are unable to assess their 'residual value', which they do in case of normal oil tankers. Therefore, LNG vessel ownership remained with very few elite players having deep pockets.

In view of the above, the majority of LNG Vessels become an integral part of the LNG Value chain right from the FID stage of a Liquefaction facility. Its ownership rests with the stakeholders of a LNG project, i.e., producers or buyers (including end-users or portfolio players). Following principles of 'cash flow waterfall', the investments risks in procuring LNG vessels are built in the revenue income and included in the costs for the Buyers. This also explains why the LNG prices are 'Delivery Ex-Ship' (DES) or delivered basis. These salient features limit nearly 85% of deployment of LNG vessels for long-term charters of upto 20 years and specifically serve the associated ports. LNG shipping is therefore not only integral but a very vital part of the LNG Value Chain and trade. Owing to these factors, only niche marine lines maintained a minimal fleet for the 'spot' market trades.

Till 2012, the trade was largely backed by Long-term contracts, and the specifications of vessels were project-specific. However, from 2012 onwards, new paradigm of LNG contracting evolved. After 2012, the long-term contracts saw changes favouring lower off-take quantities, mitigation for 'Take-or-pay', flexibility in off-take schedules, flexibility in the end-use destinations and provision for resale by the off-takers. Accordingly, specifications for new orders of LNG vessels spell flexible manoeuvrability and acceptance at multiple ports. Another visible trend is that in the orderbooks of shipyards, vessels have been ordered without long-term charters, and these are available for spot charters.

4.2 LNG Freight rates

In 2019, only about 15% of the LNG Shipping capacity is available for the short-term contracts. As such, LNG Charter rates can vary from about 30,000 to 180,000 $/day. However, with a healthy addition of carriers from 2014 onwards and a gradual increase in orders without firm charters, the average charter rates have halved to about 40 – 80,000 $/day, as brought out in the figure below:

Fig-4.2.1: Short-term charter rates from Jan 2016 to Jan 2020

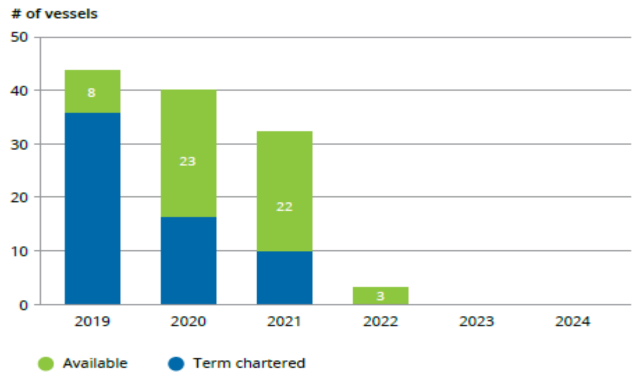
(Source: Howe Robinson / OIES)

4.3 Fleet and vessel availability

After 2012, the long-term contracts saw changes favouring consumers for their commitment quantities, mitigation measures and more flexible schedules and destinations. Accordingly, specifications for new orders of LNG vessels enable manoeuvrability and acceptance at multiple ports. Another visible trend is that in the orderbooks, many new players have become active in ordering LNG vessels without firm charters, hoping to encash upon the trade opportunities.

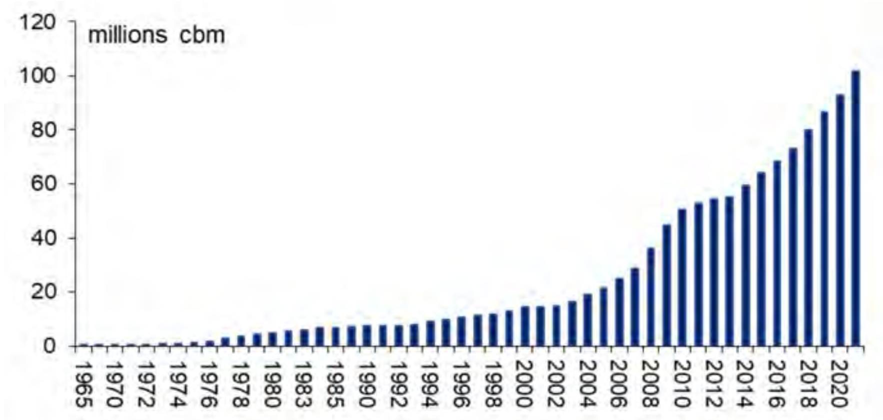
Fig-4.3.1 Future Deliveries as in 2018 of Term-Charter and Available Vessels

(Source: IHS Markit / IGU)



It can be seen that nearly 45% of the orders for about 120 LNG Vessels do not have term charters. It is an indication of more vessels being available for short-term/spot trades in the coming years. The growth in average vessel capacity and number of vessels added to the global LNG Fleet has helped in significant growth in volumetric capacity for shipping / charters. The figure 4.3.2 below brings out the growth in total volume of shipping capacity over the years. The steep rise in the curve from 2014 onwards provide comfort for short term traders as would limit the high volatility in LNG charter rates.

Fig-4.3.2: Growth of Shipping Volume Capacity (in million cubic metres)



Source: IHS / Howe Robinson

Salient features of LNG Vessels

A) Containment System

Two designs were initially conceived for LNG containment. The Moss Resenberg system started in 70s and consists of multiple spherical storage tanks, the top half exposed on the vessels and distinctly visible. The other popular design is a 'Membrane' type design, wherein the containment is covered by metal membranes packed with high quality thermal insulation in a sandwich construction. The membrane vessels are more popular and comprise nearly 2/3 of the global fleet.

Both the designs rely on expensive insulation to keep the LNG cool during the voyage. Nevertheless, some LNG evaporates during the voyage called the 'Boil off Gas' (BOG). Average BOG comprises about 0.15% of the volume. Newer designs however claim BOG as 0.08-0.07%.

B) Propulsion System

Initial LNG carriers used steam turbines as their propulsion system. From 2000 onwards, with increase in costs of bunker fuels, the need for propulsion efficience catalysed development of new propulsion systems using BOG as well as HFO or Marine Diesel Oil (MDO). The most popular propulsion systems being ordered now are:

- DFDE /TFDE (Dual or Triple Fuel Diesel Electric)
- ME-GI (MAN designed-Electronically controlled, Gas Injection)
- X-DF (Wartsila designed two-stroke slow speed dual-fuel engines)

While DFDE/TFDE and ME-GI comprise about 70-80% of the order book. DFDE/TFDE are about20% more fuel efficient than Steam Turbine driven propulsions. ME-GI & XDF are 15-20% more efficient than DFDE and gaining popularity in new orders, particularly for Short-term / Spot trades. These propulsion systems have brought down the fuel consumption to upto 60% as compared to steam propulsion. The X-DF designs are simpler and 15% less capital intensive than ME-GI and find favour with LNG Shipping lines.

C) Fleet size / capacities and age

LNG Shipping started in 1959 with a modified vessel, 'Methane Pioneer' (DWT 5,034) which carried a methane shipment from Louisiana to the UK. In early sixties, vessels of 27,000 cu mtrs of LNG Storage capacity were used for shipping LNG from Algeria. Subsequently, as the trade grew, capacities went up. Major considerations were to capture the economies of scale, drafts at the handling ports, navigation ease in crossing Suez and Panama canals and optimum utilization for time charters. Therefore, the vessel capacities settled at 125 – 150,000 cubic meters (cum). From 2008-10, LNG producers, which contracted cargoes for Japan & Korea from suppliers like Qatar & Russia ordered special Q-class vessels (Q flex of 210-216,000 cum &Qmax 260,000 -266,000 cu mtrs) for economies of scale. Even as of now, vessels of upto 150,000 cum constitute about 46-50% of the LNG fleet. After the expansion of the Panama Canal in 2016 (increase in its width and depth), and the onset of LNG exports from the USA, the capacity for new vessels has stabilised at around 170 -180,000 cum.

As per IGU, at end of 2019, there were 541 vessels available across the globe for active shipping or acting as FSRUs. The fleet comprised of 34 FSRUs and 4 FSU (Floating Storage Units). The order books with shipyards reflected 126 new vessels. Another recent report of OIES cites global deployment of about 600 vessels, with only about 15% available for spot or short-term charter with an average ship size at 180,000 cum.

D) Fleet expansion / New orders

In 2018, a record 59 vessels were delivered, marking an increase of 19.5% over the previous year. By year end, across the shipyards, orderbooks had 118 LNG carriers, with 56 for Spot Trade and 62 for Long-term charters. In 2019, 42 new vessels were delivered (against target deliveries of 43 vessels for the year), which is a growth of about 8.4% and slightly behind the growth in global trade of 13%. As per a Sep 2019 report by Argus, the orderbook for LNG vessels had expanded to 135. With limited scrapping, the fleet size is likey to grow to above 600 LNG carriers by 2020 (Reviera Maritime, 30th Dec 2019). As per Woodmac, 4 LNG vessels have already been delivered in 2020 and 38 are scheduled for delivery by year-end. In view of this, availability of LNG Vessel is likely to remain surplus till 2022.

E) Vessel Costs & delivery schedules

Prior to 2014, vessel costs hovered between $1300 to 1700 per cm. The higher prices were for the ice-breaker LNG vessels for Yamal LNG. However, post 2014, the South Korean shipyards, suffering from the downturn in shipbuilding and scanty orderbooks, bid aggressively to bring down the prices to well under $ 1100 per cm. The Japanese and Chinese shipyards were compelled to offer competitive prices. With more orders for the Neo Panamax sizes (180,000 – 200,000 cm), the rates have stabilised to below $ 1100 per cm.

The normal delivery schedule for an LNG vessel varies between 30 -40 months, depending upon the propulsion system. In case a shipping line orders a sister vessel, it can be delivered in just 24 months.

F) Fleet Utilization in voyages travelled

Fleet utilization is measured in the number of voyages undertaken by the vessels. The voyages in 2019 were 5,701 as compared to around 5,119 voyages in 2018. With the onset of exports from USA, the average voyages per tanker in 2018 had come down to 10.5 from 11 voyages/year in 2017. However, the LNG voyages to Europe increased disproportionately in 2019 due to the spurt in its LNG imports.

G) Standardization

The LNG Shipping is characterized by a limited numbers of loading ports and destinations. As of now, there are 34 active LNG load ports and 134 LNG Dischargs ports. With increase in the order for vessels for Short-term/Spot trades, there is a need for standardization of ports, vessels, port control, cargo vetting and contracting terms so that the charter contract are understood in a fair manner. To address these issues and facilitate fast contracting required for spot/short-term trade, Shell has developed new versions of its 'ShellLNGTime' charter, with standardized terms and condions. GIIGNL, the International Group of LNG Importers, publish the LNG Custody Transfer Handbook for standard practices.

H) Impact of widening of Panama Canal

In 2016, expansion of Panama Canal with a Third set of Lock Gates and increase in its width and depth has nearly doubled its capacity. The expansion was soon followed by the LNG exports from the USA, which commenced in 2017. The voyage time for LNG vessels from US east coast via the Panama Canal has reduced from the earlier 33 days to 22 days for Japan-Korea-China. Even though the transit fee has gone up by a million dollar for a round voyage, the expansion of Panama Canal has acquired a notable significance for the long-term US LNG exports.

Chapter 5: LNG Receiving Terminals (RLNG Terminal)

5.1 Characteristics of LNG Receiving terminals (RLNG)

Receiving of LNG requires a special facility capable of receiving and berthing of LNG vessels, unloading the cargo in cryogenic containment /storage tanks and re-gasifying the LNG into gas. As LNG is supplied at atmospheric pressure, it needs to be ompressed on regasification for transmission and supplies through pipelines. These terminals also act as source for small quantities supplied by road tankers or daughter vessels / barges to other nearby facilities or for bunkering LNG as a fuel in Ocean Going Vessels (OGVs).

In the early decades of LNG trade, the LNG Receiving or RLNG terminals were located on shore adjacent to ports with adequate draft, dredging and specific infrastructure for berthing and unloading. Installation of the facility required sizeable chunk of land with provision for brownfield expansion, statutory clearances and permissions from the local regulatory bodies and governments, specially trained and skilled manpower and reliable contractors, and, a minimal local infrastructure to support the project construction activities. The CAPEX is significant, about a third of the Liquefaction plant and the owners/partners need deep pockets and high creditworthiness to secure financing by banks and financial institutions. Securing of long-term off-take contracts and ease in access to local markets and gas supply infrastructure is also required. OPEX were much lower as compared to the Liquefaction plant as energy for vaporization was several times lower than that required for compressors in the LNG Liquefaction facility. The on shore RLNG terminal would invariably need 6-8 years from conception to delivery of gas.

With the growth in use of gas and its import as LNG across the globe, the need arose for sudden increase in demand, short/medium term, while the LNG terminals are either unavailable or already operating at their full capacity. The construction of Land-based LNG Receiving terminal can take 5-7 years. Besides, the local conditions may not be like amenable to construction of an on shore RLNG terminal There can be other constraints difficulties faced in the financing of the large CAPEX for new on-shore Terminal.

The above needs led to conceptualization of Floating Storage and Regasification (FSRU) terminals. The FSRU would be assembled in a shipyard on a special barge or an old used LNG vessel, customised to the required specifications. They would have mobility for being towed to a new location when required. They could be available on 'lease' basis (where the lessor pays the daily charges) or 'tolling' basis (the charges are paid for the consumption, in $/mmbtu) and the huge 'sunk cost' for an on-shore terminal can be avoided. They could be hired at short notice of say just 12 – 24 months. The FSRUs provide the following benefits over conventional land-operated RLNG terminals:

- Installation time is less. In case of the first Moheshkhali FSRU at Bangladesh, the contract was signed in July 2016 and terminal was declared operational (COD) in Aug 2018, in just 25 months. The second FSRU at Moheshkhali also began commercial operations in less than 25 months.
- Do not necessarily need a port / berthing.
- Greater flexibility in mooring point. Can be relocated to a new location if required.
- Requires less CAPEX. Besides, it is not a 'sunk cost' as in the 'on-shore' terminals. The asset is moveable and residual value is higher as it can be sold.
- Fewer regulations and environmental compliance.
- Can be available for short-term wet lease.
- Ideal for serving markets with low volumes.

The FSRU came into being from 2005 and have since gained popularity and comprise about 14-15% of the global RLNG capacity. The world wide acceptance of LNG as a fuel can be gauged by the fact that receiving terminals have also been commissioned even in LNG exporting countries/regions (like Middle East, Russia, Indonesia, Malaysia and the USA) to make gas available to inaccessible regions not connected with source.

5.2 Growth of RLNG Capacity

The LNG importers have tripled in the past 15 years. The competitive prices of LNG and benefit of lower greenhouse emissions and pollutants as compared to coal and oil, was a key driver for many countries to install these terminals and switch their fuel to gas. In2018, new RLNG capacity of 8 MTPA was added with Panama and Bangladesh being the two new entrants. Bangladesh's RLNG facility is an FSRU. In 2019, 6 new terminals were added and 3 terminals were expanded. These included 3 FSRUs, one each at Bangladesh, Brazil and Jamaica. The annual growth in RLNG capacities and their utilization from 2000 to 2024 with forecast capacity is illustrated in Figure below:

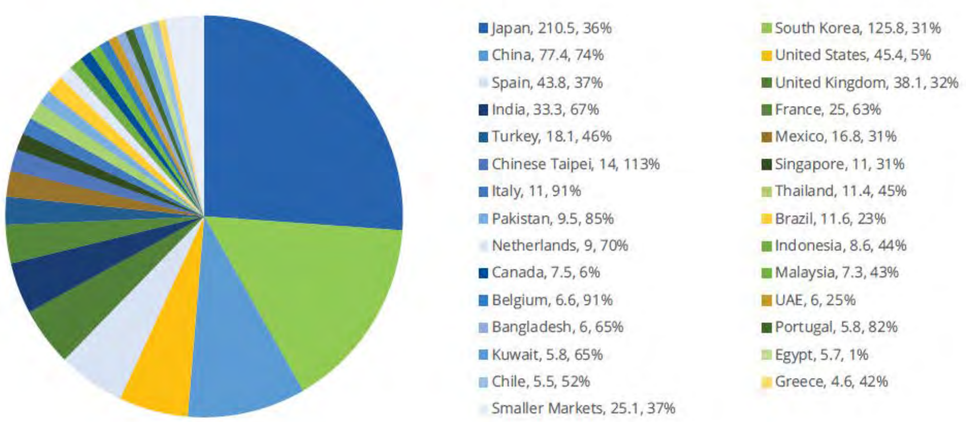
Fig-5.2.1: Growth in RLNG capacity between 2000 to 2020 and Utilization

(Source: IGU World LNG Report 2020 / Rystad Energy)

5.3 Global capacity and utilization across countries

Global capacity for the RLNG terminals is more than two times the liquefaction capacity. By February 2020, the global RLNG capacity was 821 MTPA across a total of 36 markets. Asia-Pacific countries together have 60% of the global capacity, followed by Europe (20%) and North America. By the end of 2019, Japan leads with a capacity of 210.5 MTPA followed by S Korea (125.8 MTPA), China (77.4 MTPA), USA (45.4 MTPA), Spain (43.8 MTPA), UK (38.1 MTPA), India (33.3 MTPA) and Taiwan/Chinese Taipei (14 MTPA). The requirement of USA is restricted to its domestic consumption in distant or remote areas with no pipeline connectivity. An overview of the country-wise capacities and utilization is as follows:

Fig-5.3.1: Regasification capacities by countries and Utilasation



(Source: IGU World LNG Report 2020 / Rystad Energy)

The SmallerMarkets are those having capacities of less than 4 MTPA.

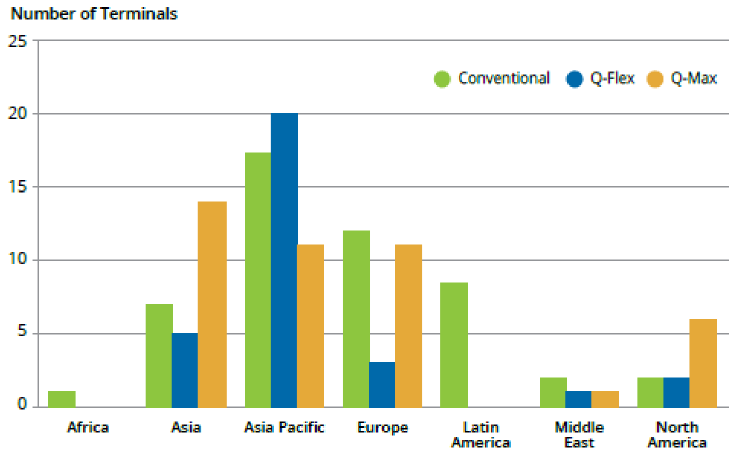
While the average utilization in 2019 was 43%, it is higher in countries with growing demand like Chinese Taipeh (113%), China (74%), Pakistan (85%), India (67%), and Bangladesh (65%).

5.4 RLNG Terminals: Storage and Berthing capacity

The LNG unloaded from the LNG vessels is stored in cryogenic tanks. This storage capacity is of significance as it provides a buffer till the availability of new shipments. Besides, adequate storage capacity can help in normal unloading while the plant undergoes some maintenance. So countries carefully work out their LNG Storage capacity. For example, Japan has about 25% of the global RLNG capacity, but its storage is about 28% of the global capacity.

Berthing capacity at an RLNG facility also needs careful consideration. It is desired that berthing facility at port is flexible to accommodate vessels of various sizes including Q-Class vessels.

Fig-5.4.1: Maximum Berthing Capacity of RLNG Terminals by Region

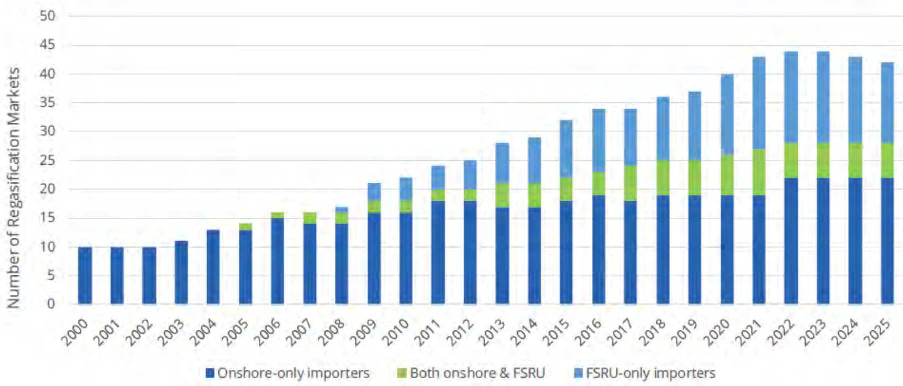


(Source: IGU World LNG Outlook 2019, IHS Markit)

5.5 RLNG Growth projections: Firm Capacity addition till 2025

New countries like Ghana, El Salvador, Phillipines, Cyprus and Croatia have their FSRUs under construction and should become operational by 2020-2022. Countries where their domestic gas production is declining or demand is increasing like Bahrain, Morocco, the Phillipines and Vietnam have also announced plans for installing RLNG plants. As on Jan 2019, about 129.7 MTPA of RLNG / FSRU facilities were under some stage of construction. The rise of FSRUs and On-shore plants and likely forecast till 2024 is mapped out in the figure below:

Fig-5.5.1: Growth of Regasification Markets by Type (2000 to 2025)

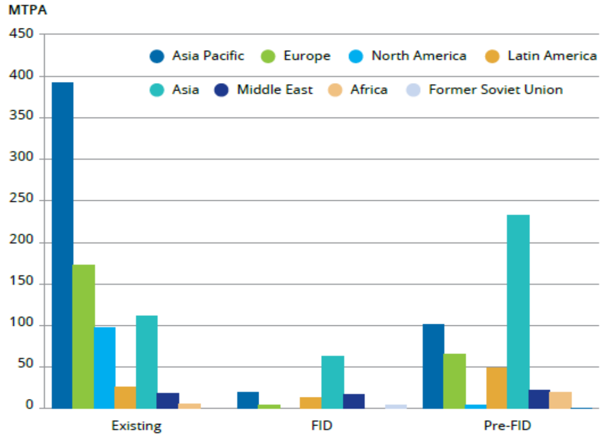


(Source IGU World LNG Report 2020, Rystad Energy)

5.6 RLNG: FID status for region-wise capacity additions

Asian countries led by China, India and other South Asian & South East Asian counties are key to the future growth in RLNG capacity additions. China, India and Pakistan lead the pack with FID achieved for 60 MTPA capacities. Asian countries also have plans for nearly 240 MTPA of capacity addition in Pre-FID stage. Region-wise existing, FID and Pre-FID capacities are illustrated in the figure below:

Fig-5.6.1: RLNG Capacity by Region and Status (as of Feb 2019)



(Source: IGU World LNG Report 2019 /IHS Markit)

The key enablers to the materialization of these RLNG Terminals are the pace of downstream pipeline infrastructure, availability of affordable LNG and the reduction in capital costs.

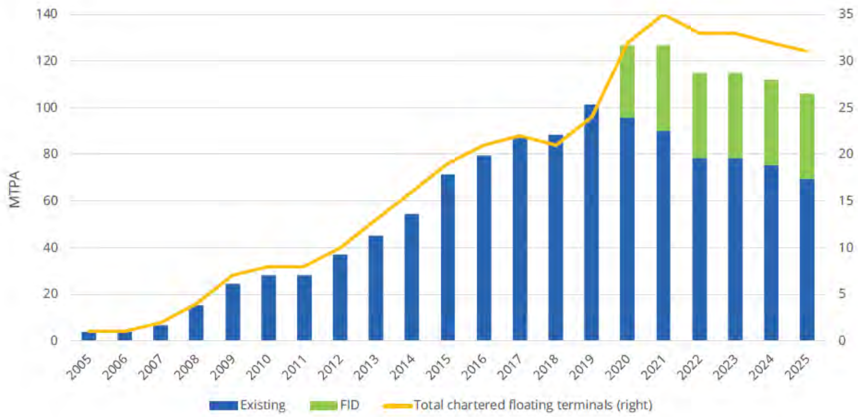
5.7 Recent Trends in RLNG

(i) Emergence of FSRUs

The benefits of FSRUs over a land-based LNG Receiving terminal have been enumerated at Para 5.1 above.

A large number of markets decided to opt for FSRUs after the first two were commissioned at Egypt and Pakistan in 2005. As in 2019, out of 36 RLNG markets, 16 had one or more FSRU installed. As in early 2019, 12 out of 29 RLNG facilities under construction were FSRUs. The growth of the terminals from 2005 to 2024 is illustrated in the figure below:

Fig-5.7.1: Growth of FSRU in numbers and total capacity



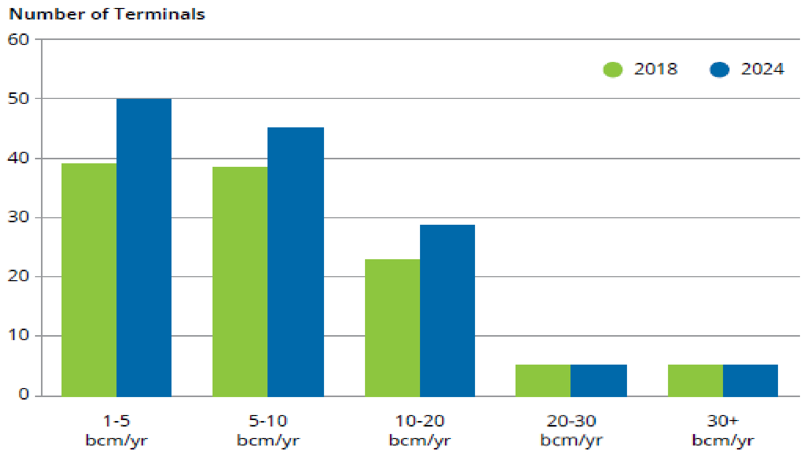
(Source IGU World LNG Report 2020, Rystad Energy)

FSRUs support faster and more flexible capacity addition, as also seen in Egypt, Pakistan and Bangladesh. The disadvantages are that OPEX is more compared to on-shore terminals and they come in limited capacities with little scope for 'brownfield' expansion at a later date. Another constraint is that their operations are subject to weather and sea conditions and there is an element of uncertainty in the supplies. The FSRUs at Bangladesh faced operation problems due to rough sea conditions prevalent in the Bay of Bengal.

ii) Nameplate Capacity of RLNG Terminals

Like Liquefaction plants, the RLNG terminals too are complex and expensive to install. Over the years, economies of scale, metallurgical innovations in new materials, design configuration and energy efficiency in process have been improved upon to optimize the CAPEX and OPEX per unit of LNG. The figure 5.7.2 below depicts number of existing RLNG terminals and their nameplate capacities in 2024 as compared to 2018 and brings out the trend for opting for higher capacities for the new installations:

Fig-5.7.2: Trend for opting for higher nameplate capacities: 2018 to 2024



(Source: IHS Markit / IGU World LNG Outlook 2019)

B) Diversified RLNG terminals - Reloading and transhipment capabilities

A key trend is to design terminals with value added services like Transshipment (or Re-export), small scale LNG Bunkering and truckloading.

European terminals have long been using re-exports as an optimization strategy for efficient and cost-effective operations of their terminals. In 2019, France led the re-exports with 0.6 MMT, followed by Singapore (0.4 MMT) and other countries like Jamaica, Netherlands, Spain, Belgium.

About 92% of the global LNG Fleet utilizes boil-off gas as fuel for its propulsion .The new regulations of International Maritime Organization in 2020 (IMO 2020), limits Sulfur to less than 0.5% in bunker fuels. It is likely to spur the new orders of shipping fleet equipped with LNG. This is considered as one of the most significant development that is likely to spur the growth in LNG consumption.

C) Floating Storage Units (FSU)

Floating storage units are essentially LNG vessels and used along with a regasification platform. FSU may also be used as buffer to the storage capacity which comes handy for spurt in demands as experienced during winter shavings or due to decline of supplies from domestic production or pipeline imports. In 2019, 4 new FSUs have been added to the LNG Fleet across the globe.

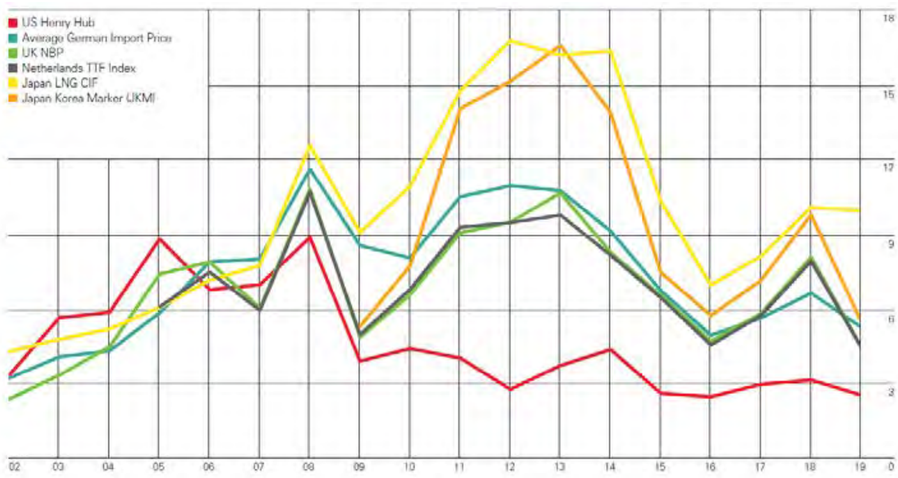
Chapter 6: LNG Pricing, Trade and Trends

6.1 LNG Pricing overview

In consideration of the large CAPEX required for the Liquefaction facilities and the LNG Shipping, long-term contracts with 'Take-or-Pay' were entered with the buyers. The duration of these contracts were of 20 years. The pricing was often linked with crude between 13% –14% parity (more often with a floor price ceiling for the seller.

Over the years, gas markets have matured with liquid trading hubs in Europe. The National Balancing Point (NBP) in UK, Title Transfer Point (TTF) in Netherlands, German Border Gas price in Germany have matured as gas hubs for liquid trade. The hub prices have followed correlation with the rise and fall in crude as well as gas demand. From 2009, for renewal of gas price in Long-term contracts or new contracts, European buyers insisted and prevailed over to include gas hub price indexation. This was the beginning of Gas-on-Gas (GOG) pricing mechanism with price indexation based fully or partly on the hub prices. The following figure shows the gas prices (in s/mmbtu) from 2002 to 2019 across various markets, i.e., on Henry Hub(in USA), NBP (in Great Britain), Title Transfer Point (TTF in Netherlands), Japanese LNG CIF & Japan Korea Marker (JKM) and Average German Import Price.

Figure-6.1.1: Gas Prices in key markets across the globe



(Source:BP Statistical Review of World Energy 2020)

It can be seen that the Henry Hub prices have witnessed a steady decline post the shale boom from 2009 onwards. The J-K-M prices were higher between 2011 to 2015 and again in 2018 due to higher crude prices and tight LNG markets. However, it is reiterated that for LNG trade, Oil-indexed pricing is still dominant, even though on decline.

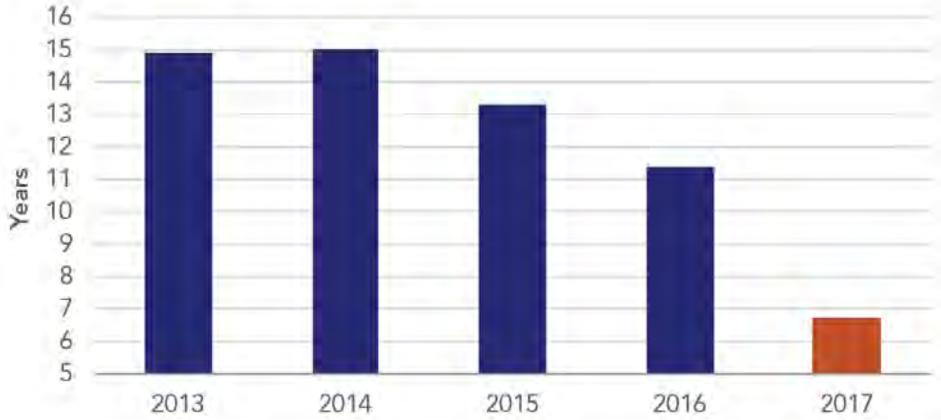
6.2 Key shifts in LNG Contracts and Pricing

The period 2010 to 2014 was a period of high prices of crude. The Fukushima Daiichi Nuclear disaster in 2011 forced the shutdown of all nuclear capacity of Japan and led to a sudden spurt in demand for oil & gas resulting in sustained high prices of LNG. For the new contracts, the key concern for the buyers was the high indexation of LNG prices with crude. Following the shale boom, USA turned to become an exporter of gas and this period also witnessed the launch of several LNG Liquefaction projects in the USA. Post 2012, there has been a distinct shift in the terms of LNG Contracts and pricing in favour of the buyers. The key shifts were as follows:

a) Shorter terms of contracts

The contracts signed in post-2016 onwards have seen dramatic shift towards smaller volumes and shorter terms. The figure below maps the average contract terms between 2013 to 17. In 2017, average term of a contract fell to just 6.7 years in 2017 compared with 11.5 in the previous year.

Fig-6.2.1: Average term of all LNG Contracts signed between 2013-17



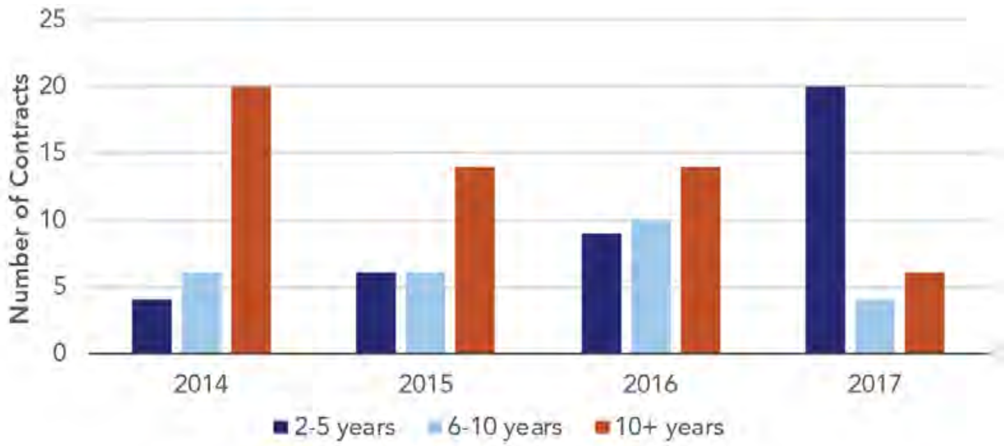
(Source: Poten Partners)

However, BP in its LNG Outlook 2020 has cited reports of Wood Mackenzie and IHS Markit that average term of LNG Contracts have increased in 2018 & 2019.

b) Increase in numbers of short-term contracts

The number of short-term contracts, 2-5 years and 6-10 years increased and contracts of 10+ years have plummeted (as shown in the figure below)

Fig-6.2.2: Number of contracts for short, medium and long term from 2014-17

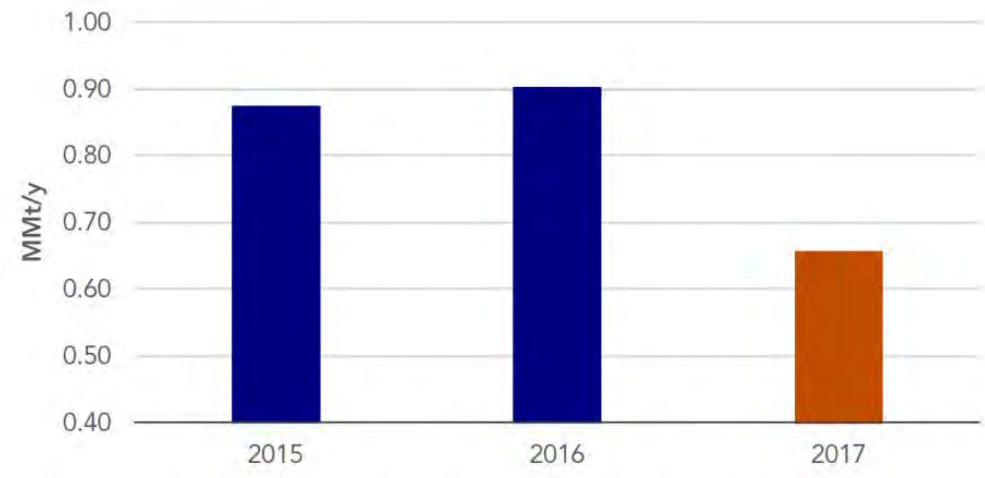


(Source: Poten Partners)

c) Reduction in average volume per contract

The average volumes per contract also shrank from 0.9 MTPA in 2014 to 0.66 MTPA in 2017, as brought out in the figure below:

Fig-6.2.3: Average Annual Contracted Quantity per contract from 2015 to 17

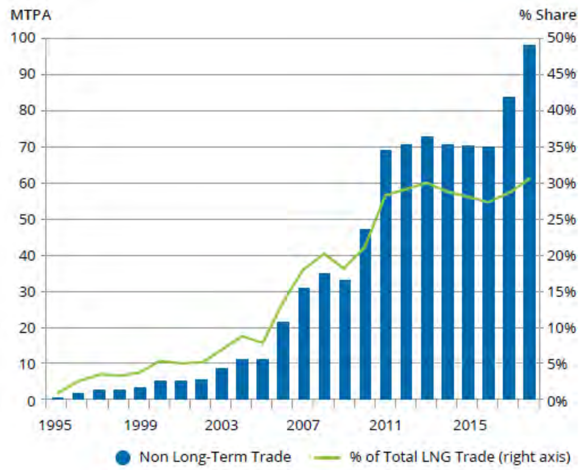


(Source: Poten& Partners)

d) Increased share of short-term contract in LNG Trade

The share of non-long term contracted gas in total volume of LNG has increased from 10% in 2010 to above 48% in 2019, as in the figure below:

Fig-6.2.4: Share of Non Long-term trade volumes and share in total trade

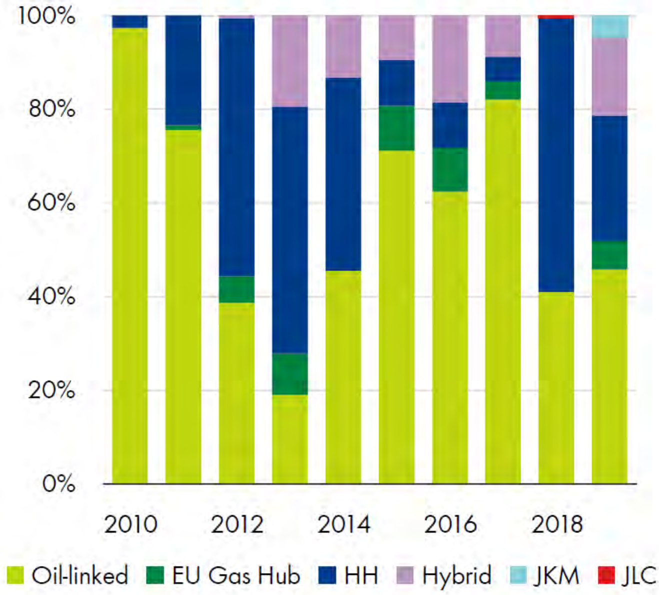


(Source: IHS Markets / IGU)

e) Indexation of price

Shift from Oil-linked to Gas Hub -linked/ Hybrid indices Post 2012, the buyers insisted and sellers agreed for also including gas-on-gas indexation. The contracts were increasingly signed for indexation with Gas Hubs, like Henry Hub, EU Gas Hubs (i.e., National Balancing point (NBP), UK and later Title Transfer Facility (TTF), Japan-Korea Marker (JKM) or a Hybrid of oil & gas indices. In 2018, for the first time an LNG contract had prices indexed with coal. The trend is mapped in the figure below:

Fig-6.2.5: Share of the indexation type in the new contract volumes



(Source: Shell LNG Outlook 2020)

As per a recent Mckinsey report, the Oil-linked LNG in new contracts entered between 2015 to 2019 has declined from 66% to 59%.

f) Softening of the oil indexation

The Fukushima disaster had pushed the oil indexation level to above 14%. In 2015, the decline in the crude prices pulled down the indexation to 12% by 2016. Subsequently, lower spot gas prices has further brought down the oil indexation to aound 11% in the mid-term and long-term contracts as below:

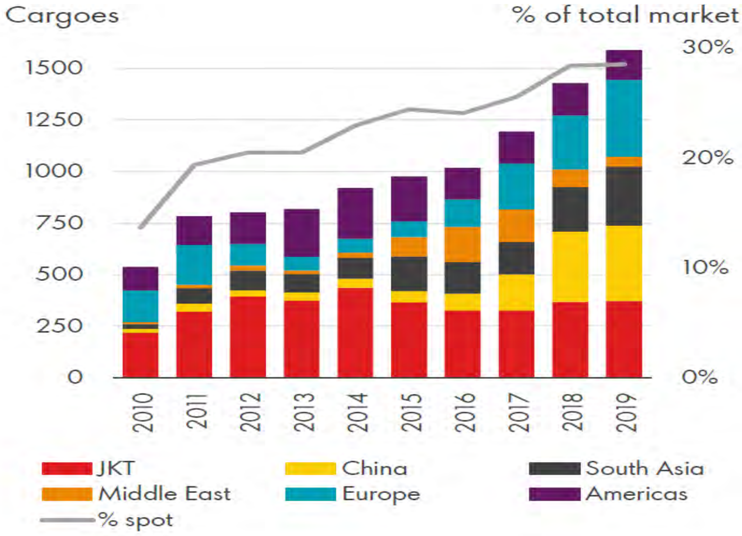
Fig-6.2.6: Oil Indexation in LNG Sale Purchase Agreement (SPA) over the years

(Source: Rystad Energy / IGU World Energy Report 2020)

g) Increase in Spot and derivative trade

The share of 'Spot' cargoes, which were a mere 10% of the total global volume of LNG in 2010, rose to above 30% in 2019. The growth is mapped in the following figure illustrated by Shell in its LNG Outlook 2020:

Fig-6.2.7: Share of Spot Cargoes in Global Trade



(Source Shell's Interpretation of IHS Markit, S&P Global Platts and ICE 2019 in Shell's LNG Outlook 2020)

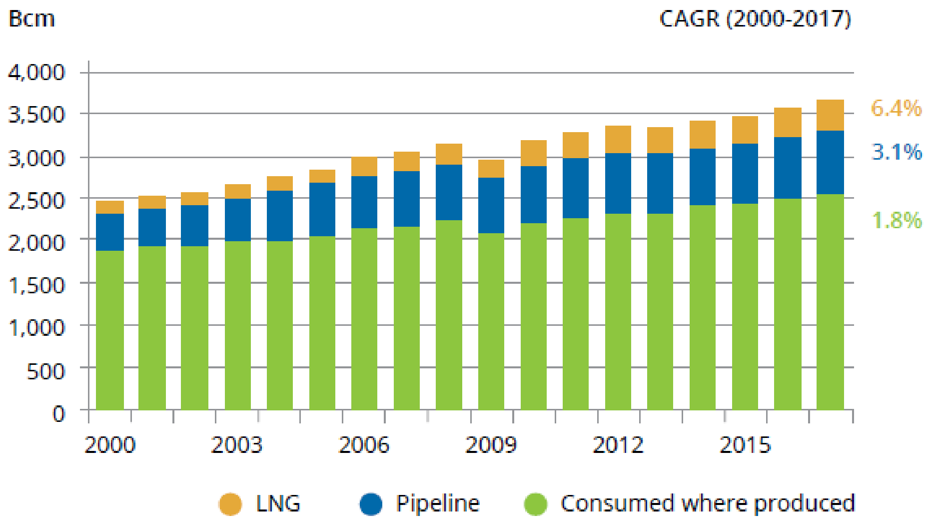
Yet another shift in recent contracts is flexibility in end use, option for resale, flexibility in destination etc. The Portfolio players have also strengthened their hold in LNG supplies. By 2025, Portfolio players shall hold 31% share of the global LNG, up from just 24% in 2019.

These changes like decline in long-term contracts, increase in short-term contracts, higher volumes of short-term contracts, lower price indexation with crude and increased footprints of Portfolio players indicate 'commoditization' of LNG and are likely to improve the availability and marketability of LNG.

6.3 LNG Trade: Past growth

Over the years, LNG consumption had found favour due to the price arbitrage over substitute fuels in terms of heating value. At many places, the domestic gas production and pipeline flows have declined, leading to consumers leaning to LNG imports. The concern for global warming and the harmful impact of emissions from coal-based thermal plants on the environment and health has seen a gradual shift towards gas-based generation. Since 2000, LNG trade volumes have grown at CAGR of 6.4% per annum. The year-wise growth in LNG trade from 2000 to 2018 has been summarised below:

Fig-6.3.1:Yearwise growth in LNG trade 2000 to 2017

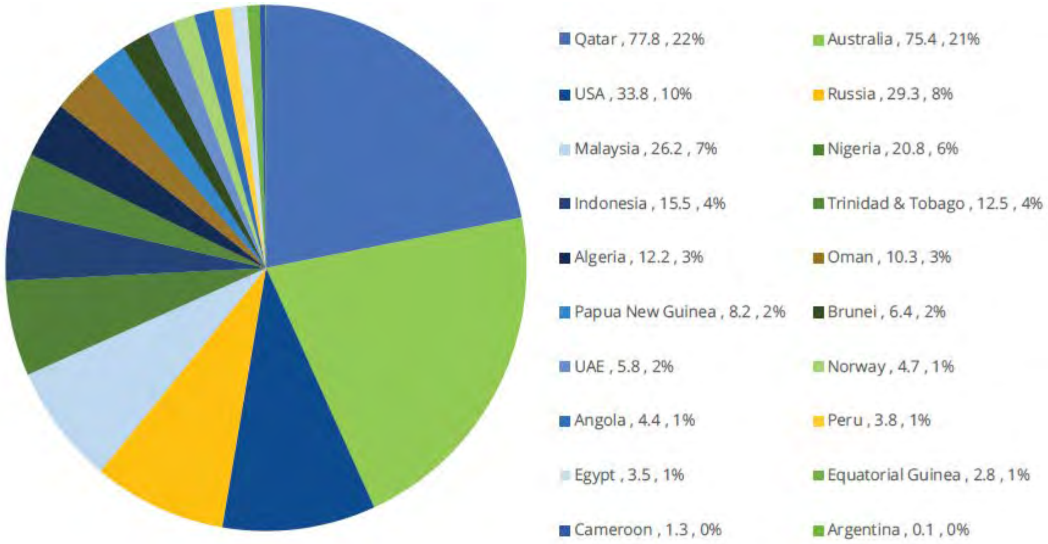


(Source: IHS Markit / BP Statistical Review /IGU)

6.4 LNG Exports and Imports

i) Exports: In 2018, LNG trade increased by about 28 MT over the previous year. In 2019, LNG exports recorded a growth of 40.9 MMT, or about 13% over 2018, and touched 354.7 MMT,. The US and Russia increased their exports significantly. The largest exports additions came from the US (+13.1 MMT over 2018), Australia (+8.7 MMT over 2018) and Russia (+11 MMT over 2018). The country wise exports were as follows:

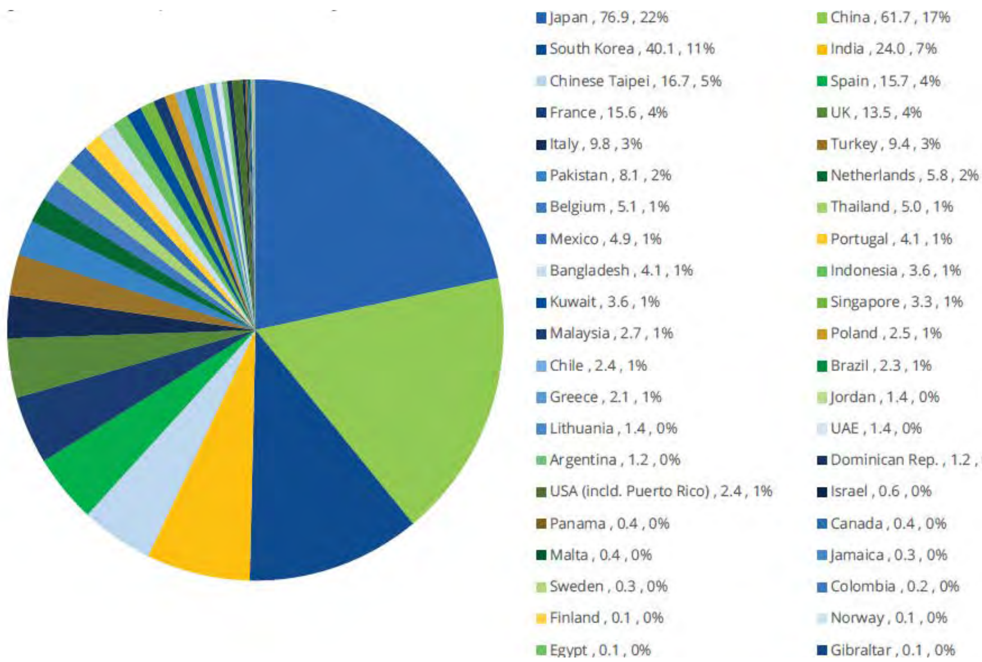
Fig-6.4.1: Country-wise LNG Exports and their share in 2019



(Source IGU World LNG Report 2020, GIIGNL)

ii) Imports: In 2019, Japan, China & South Korea were the leading off-takers of LNG in 2019. Japan & Korea switched to more Nuclear and Coal-based generation, and recorded a decline in LNG imports by about 10.7 Million MT. However, Europe's domestic production declined and it absorbed most of the growth in LNG supplies. Europe increased its imports by 32 MMT during the year. China was the second highest importer, behind Japan, with a growth of 6.9 Million MT in 2019. However, the year-on-year growth in China's demand declined from 40% in 2018 to about 14% in 2019.

Fig-6.4.2: LNGImports by Country and their share in 2019



(Source IGU World LNG Report 2020, GIIGNL)

The abundant supply of LNG contributed softening of the prices and added to growth. It can be seen that declining domestic gas production in South and South-East Asia, and a new terminal at Bangladesh lead to an increase of demand by 21% in this region. Together between them, India and Bangladesh increased their imports by a total 5.1 MMT.

6.5 LNG Intra-regional Trade

Asia-Pacific and Asian countries consumed about 246.2 MMTPA between them, which is nearly 70% of the global trade. The LNG inter and Intra regional trade is mapped in the table below:

Fig-6.5.1: LNG Trade between Regions

Exporting Region / Importing Region	Asia-Pacific	Middle East	Africa	North America	Former Soviet Union	Latin America	Europe	Reexports Received	Reexports Loaded	Total
Asia-Pacific	77.3	31.2	2.9	9.5	8.8	2.1	-	0.3	0.4	**131.7**
Asia	54.2	36.3	13.6	3.0	4.8	1.9	0.1	0.8	0.1	**114.5**
Europe	-	23.5	25.1	12.7	15.1	5.9	4.2	0.3	0.9	**85.9**
Latin America	-	-	0.8	4.2	-	2.6	0.4	0.1	-	**8.1**
North America	0.2	-	1.5	2.9	0.1	3.1	-	-	-	**7.7**
Middle East	0.1	3.0	1.0	1.4	0.6	0.8	-	0.1	-	**6.9**
Africa	-	-	0.1	-	-	-	-	-	-	**0.1**
Total	**131.7**	**93.9**	**45.0**	**33.8**	**29.3**	**16.3**	**4.7**	**1.6**	**1.6**	**354.7**

(Source IGU World LNG Report 2020, GIIGNL)

6.6 Growth in Pipeline exports and impact on LNG trade

It is imperative that in any market that imports gas by Transnational Pipelines as also LNG, the cheaper option would first be maximised to its capacity. Therefore, for the future gas imports for such markets, gas supplies from Trans-national Pipeline compete with LNG.

In this context, the following Trans-national pipeline projects are expected to significantly contribute to gas exports and are likely to affect future LNG trade for Europe and China.

A) Nord Stream 2 (Russia – Germany, 1222 kms)

The Nord Stream 1 is the existing longest sub-sea twin pipeline of 48 inches each connecting Russian gas fields to mainland Europe, from Vyborg, Russia to Greifswald, Germany. The capacity of Nord Stream 1 twin pipelines is about 55 bcm (approx 150 mmcmd) and became operational from Nov 2011 & Oct 2012 respectively.

Nord Stream 2 (Ust-Luga to Greifswald) also has 48-inch twin pipelines. The project started in 2018-19. The project cost was estimated at about 14.8 Bn Euros (6 Bn Euros for On-shore pipelines and 8.8 Bn Euros for Off-shore pipelines). Target completion was middle of 2020. Gazprom holds 51% equity and the rest is with Uniper (Germany), Engie (France), Gasunie (Dutch gas company), OMV (Austria) & others. Gazprom has financed 50% of the cost and the rest is as loans from Banks/FIs/Project Stakeholders. Nearly 90% of the project is completed including the compressor stations on the Russian side and receiving station on the German landfall.

However, with only laying of the last 150-200 kms of pipeline remaining, the US has imposed sanctions in Dec 2019, aimed to marginalize the increased dominance of Russia over European gas supplies. Both, Russia & Germany have strongly criticised the sanctions. The EU is divided and a sizeable lobby supports completion of this project as many of the contracting agencies are from Europe. Ukraine, Poland and some Central & Eastern European countries support the sanctions.

It is learnt that Russia is planning to deploy its own resources including its own special Vessels, Akademic Cherskiy' (earlier deployed on the Pacific coast in East Russia) and 'Fortuna' for laying the remaining sub-sea pipelines. The completion is likely to get delayed till Quarter 3 or 4 of 2021. A key significance of this pipeline project is that once completed, the gas supplies will ease European demand for LNG by about 30-40 MTPA.

B) TANAP (1841 kms) (Trans-Anatolian Natural Gas Pipeline)

This pipeline connects the gas fields of Azerbaijan to Turkey and Europe. The pipeline was commissioned on 30th Nov 2019. The existing through-put is about 16 BCM (or 44 MCMD, 28 for Europe and 16 for Turkey). Backed up by future supplies from Turkmenistan, The pipeline shall be scaled upto 23 BCM by 2023, 31 BCM by 2026 and 60 BCM by 2030. This is likely to ease the gas supplies for Turkey, Greece, Albania and Italy, and reduce their dependence on gas imports from Russia and LNG.

C) TurkStream (930 kms, set of two 32 inch pipelines, Final capacity 31.5 bcma)

It is a twin 32-inch pipeline project for supplies from Russia across the Black sea in two legs, one for Turkey, and the second one for Bulgaria, Serbia, Hungary, Slovakia & Austria. It can carry about 44 MMCMD in each stream. This pipeline also faced US Sanctions imposed in Dec 2019 under PEEPSA. However, the first part of the pipeline upto Turkey has been commissioned in Jan 2020. The gas flows on from Turkey to Bulgaria and from there to Romania, Ukraine, Greece and North Macedonia via the Transbalkan Pipeline. The completion of the second part shall further ease in meeting the energy requirements for the receiving nations and help Russia to monetise its gas assets, besides in leveraging economic clout in the region.

D) Power of Siberia (Russia to China, (6,000 kms Capacity- 38 BCMA / 105 MMSCMD)

Power of Siberia is a 56-inch Pipeline capable of delivering 38 BCMA (about 100-105 MMCMD). The pipeline has been jointly constructed by Russia and China. Russia has constructed a comprehensive pipeline network that connects its Arctic & Siberian gas & oilfields (Arctic East and Central Siberia oil & gas field) to Vladivostok. A western arm of this network, called the 'Power of Siberia'pipeline connects these fields with China.

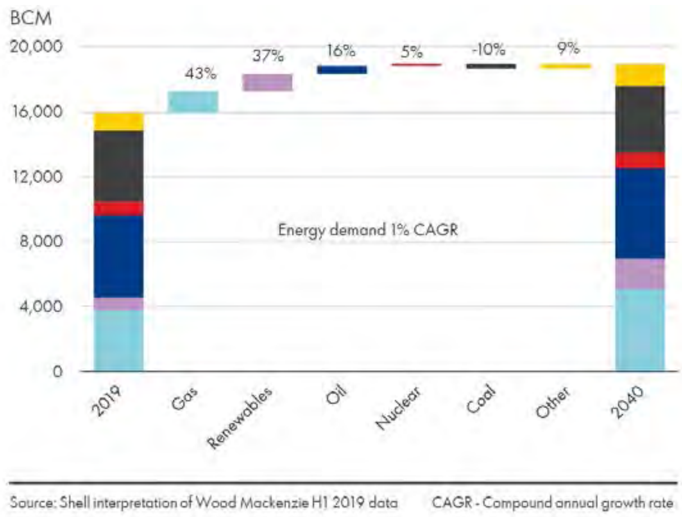
The pipeline was commissioned on 2ndDec 2019. Total investment incurred was 55 Bn USD. The pricing terms are not disclosed. The supply contract is estimated at $400 Bn over a 30-year term. However, industry sources estimate the gas price in the range of 5.5 to 6.5 $/mmbtu. This has been a strategic pipeline for Russia and China. For Russia, it helps in monetizing its gas reserves which had to be liquefied for access to consumers. For China, it help to meet its energy requirement, reduce dependence on LNG and imports, optimize its pipeline network and above all, has improved the negotiating power of China for better price and other terms in its future LNG sourcing.

Chapter 7: LNG - Long-term Demand and Supply

7.1 Global source-wise demand till 2040

A report by Shell 2040 projects that natural gas and LNG shall meet 43% growth in world's additional demand for energy, with renewable accounting for 37% growth (Refer Figure 7.1.1 below).

Fig-7.1.1: Share of different sources in 2019 (H1) and growth and share in 2040 (Shell / Wood Mackenzie)



It may be seen that the share of gas and renewables would together account for 80% of the growth till 2040.

7.2 Gas and LNG Demand till 2040

7.2.1 Gas Demand till 2040

The increase in demand for LNG is almost certain, either as the sole source of gas in many markets or to supplement the domestic production and pipeline imports.

For power generation, gas-based stations produce 40-50 % less greenhouse emissions and one-tenth of air pollutants than the coal-based stations. Over the recent years, gas has emerged as preferred fuel over coal in countries with high-income or low access to coal.

IEA in its World Energy Outlook 2019 has projected three scenarios, the Stated Policies, Sustainable Development and Current Policies. Gas projections are lowest in the Sustainable Development Scenario and highest in the Current Policies. The projections in the Stated Policies scenario is somewhere between the two scenario, which are are follows:

Table-7.2.1: IEA projections for Global gas demand, production and trade Scenarios (in BCM)

			Stated Policies		Sustainable Development		Current Policies	
	2000	2018	2030	2040	2030	2040	2030	2040
Power	908	1 571	1 708	1 936	1 580	1 248	1 823	2 197
Industrial use	644	909	1 229	1 474	1 108	1 114	1 243	1 527
Buildings	651	846	945	998	740	557	1 011	1 131
Transport	70	137	200	295	268	330	181	249
Other sectors	257	490	639	701	568	605	681	788
World natural gas demand	**2 530**	**3 952**	**4 720**	**5 404**	**4 264**	**3 854**	**4 940**	**5 891**
Asia Pacific share	*12%*	*21%*	*26%*	*28%*	*29%*	*34%*	*26%*	*28%*
Low-carbon gases	-	4	53	90	138	269	29	52
World total gases	**2 530**	**3 956**	**4 773**	**5 494**	**4 402**	**4 123**	**4 968**	**5 943**
Conventional gas	2 318	3 004	3 293	3 694	3 004	2 689	3 433	3 926
Existing fields	2 318	3 004	2 200	1 659	2 200	1 659	2 200	1 659
New fields	-	-	1 094	2 035	804	1 030	1 234	2 266
Tight gas	148	274	267	238	262	141	253	232
Shale gas	3	568	1 020	1 290	863	871	1 113	1 532
Coalbed methane	38	88	103	129	101	103	102	143
Other production	-	3	36	54	34	50	38	58
World natural gas production	**2 507**	**3 937**	**4 720**	**5 404**	**4 264**	**3 854**	**4 940**	**5 891**
Shale gas share	*0%*	*14%*	*22%*	*24%*	*20%*	*23%*	*23%*	*26%*
LNG	136	352	598	729	608	636	633	768
Pipeline	378	436	528	549	463	358	589	704
World natural gas trade	**514**	**788**	**1 126**	**1 278**	**1 071**	**993**	**1 222**	**1 472**
Share of production that is traded	*20%*	*20%*	*24%*	*24%*	*25%*	*26%*	*25%*	*25%*
Henry Hub price ($2018/MBtu)	**6.1**	**3.2**	**3.3**	**4.4**	**3.2**	**3.4**	**3.8**	**5.1**

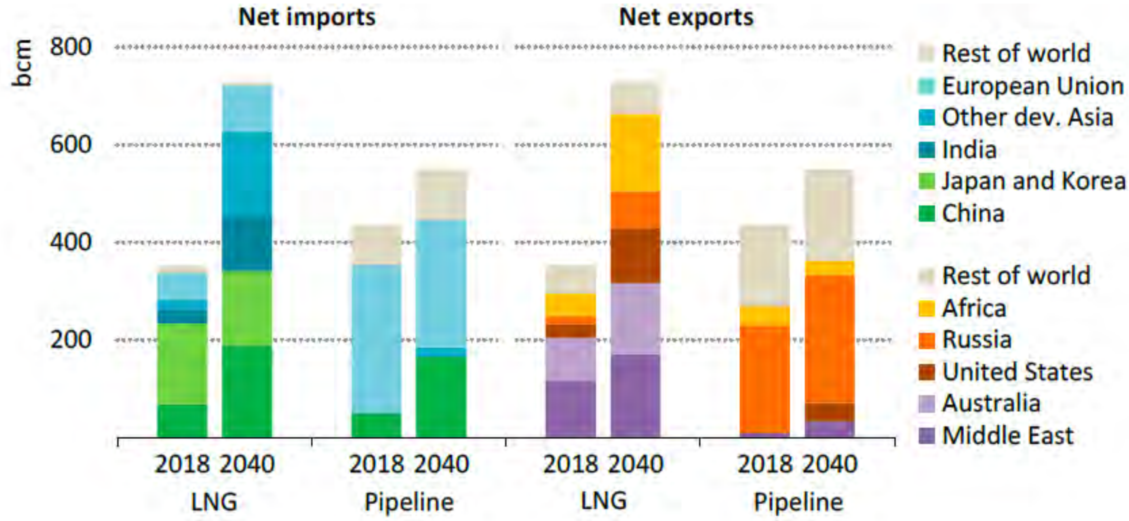
(Source:Word Energy Outlook 2019)

7.2.2 LNG Demand till 2040

The growth rate of LNG exports is nearly two times that of pipeline exports and the trend is likely to continue. Asian countries are likely to absorb 70% of the increase in demand for gas. New spot-trading mechanisms, a wider variety of indices for long-term contracts, more availability in spot / short-term trades are likely to add to Demand, which is expected to surpass 700 MTPA by 2040.

As per the IEA's World Energy Outlook – 2019, the demand for LNG is likely to grow from 352 MTPA in 2018 to about 729 MTPA in 2040 in the Stated Policy scenario as in the table 7.2.1 Above. The region-wise growth in exports and imports has also been compiled in the report. The region-wise contribution in the growth till 2040 is mapped in the figure as follows:

Fig-7.2.2: Growth of gas in Stated Policies Scenario by IEA till 2040

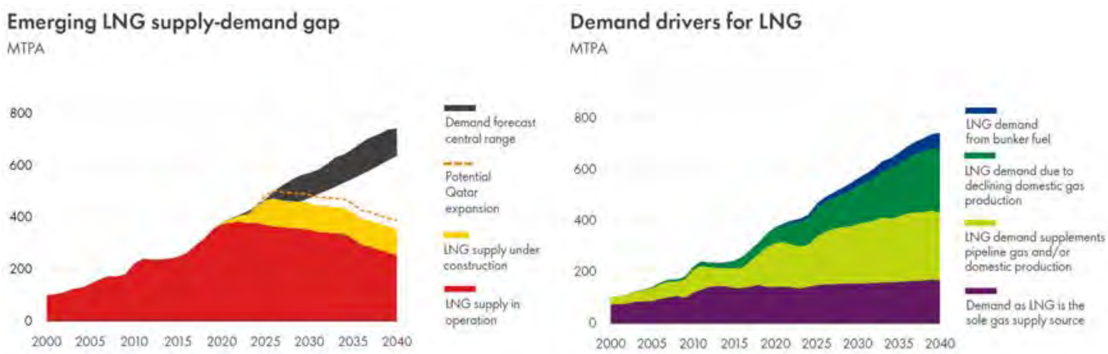


(Source: IEA WEO 2019)

7.3 LNG: Demand – Supply gap in 2040

In its LNG Outlook 2020, Shell has projected that the LNG demand for the different gas markets is likely to be around 725 – 750 MTPA by 2040. Further, demand may climb up due to decline in the existing gas production and pipeline supplies in many markets, and increase in demand for Bunker fuels. The Demand and Supply estimations have been compiled supported by IHS Markit, Poten& Partners, Wood Mackenzie & FGE as below:

Fig-7.3.1: Key Demand Drivers for LNG till 2040



(Source: Shell LNG Outlook 2020)

It may be seen that even after considering the LNG from all projects which are under construction or have achieved FID and the capacity addition by Qatar, there is a gap of about 200 to 300 MTPA, which would have to be met from new capacity addition.

7.4 LNG: Asian Demand

Asian markets constitute 72% of the global LNG demand. The growth of LNG in main Asian countries, China and India, has been in double digits as in the following table:

Table-7.4.1: LNG growth in key Asian countries

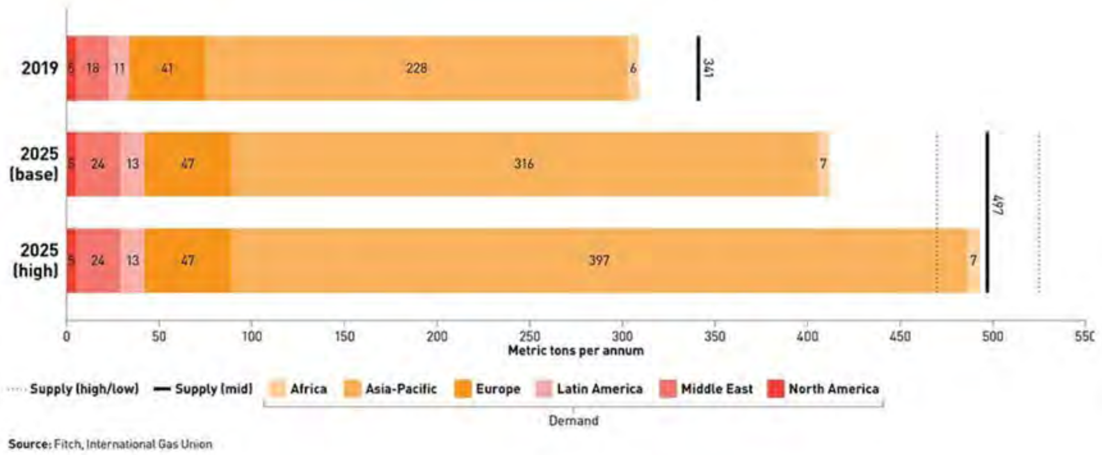
	2005-2010	2010-2015	2015-2018
China	n/a	14.8%	38.2%
India	15.7%	10.6%	12.3%
Japan	3.9%	3.3%	-5.0%
South Korea	8.5%	-1.3%	9.8%
Taiwan	10.1%	4.1%	5.9%
Total - Asia	**7.9%**	**5.1%**	**10.0%**

In South Asia, India, Pakistan and Bangladesh have witnessed static or declining domestic gas in recent years. In 2019, with addition of Regasification capacity, growth in demand has grown in India, Pakistan & Bangladesh.

All the reports on energy forecast by different research organizations have confirmed Asia and Asia Pacific as the key drivers of growth in global LNG consumption. IEA has identified these markets as drivers for future growth. As per the projections of IEA's WEO, the share of Asia- Pacific in the overall gas consumption is likely to increase from 21% in 2018 to 28% in 2040.

As far as only growth of LNG is concerned, as per a recent Fitch-IGU report, Asian markets shall account for 80 to 90% of the growth in Base and High demand case as in Figure 7.4.1 Below.

Fig-7.4.1: REGIONWISE LNG GROWTH PROJECTIONS 2019 – 2025 (IN MTPA)



(Source IGU / Fitch)

7.5 LNG: Analysis of country-wise demand in key Asian markets

1. Japan & South Korea:

These countries have been the pivot of the global LNG trade ever since it began in the sixties. 1995, Japan and Korea together accounted for about three-fourth of the global LNG trade. By 2000, as many European countries installed RLNG terminals and began to import LNG, Japan and Korea accounted for two-thirds of the total LNG trade. In 2019, while their gas consumption has grown by 50% over that in the year 2000, they imported 117 MTPA of LNG and accounted for one-third of the global LNG trade.

The year 2019 saw the LNG consumption decline in Japan and Korea. About two thirds of Japan's LNG is consumed by is power plants. Post-Fukushima disaster in 2011, Japan switched over to LNG and its LNG consumption increased by about 30%. It has refurbished some of its nuclear power plants to meet more stringent safety protocols and standards. As renewable and nuclear power generation picked up in 2019, its demand for LNG declined. As per IGU World LNG Outlook 2020 & GIIGNL, Japan's LNG consumption in 2019 fell to 76.9 MMT from 83.2 MMT in 2018. Japan is also driving policy initiatives for improving demand-side efficiencies and capacity addition of renewable. Its LNG consumption is likely to decline to 60-70 MTPA by 2030.

S Korea had faced unforeseen outages at its Nuclear power units and its RLNG imports grew by 21% in 2018. In 2019, Korea has re-commissioned its capacity on Nuclear and Coal-fired power plants, and its LNG consumption came down to 41 MMT from 44.5 MMT as in 2018. However, driven by its policy to reduce Nuclear and Coal-fired plants, its consumption could go up to about 47-53 MTPA by 2030.

Collectively, the demand in Japan-S Korea is likely to decline by about 10-15 MTPA by 2030.

2. China:

In 2018, the demand for gas was 270 bcm, out of which, 55% was domestically produced and about 17-18% was from the two Trunk Pipelines, (the Central Asian pipeline connection Turkmenistan, Uzbek and Khazakh and the Myanmar Pipeline) and the remaining 28% (about 70 bcm or 55 MTPA) was imported as LNG. Backed by a Federal decision to switch fuel of its power plants from coal to gas, the LNG imports in China grew at a phenomenal rate of 40% y-o-y in 2017 & 2018. In 2019, China's LNG imports grew by 6.9 MTPA over the 2018 imports. However, due to economic slowdown, growth rate of LNG imports declined to 14% in 2019.

China has a diversified plan for meeting its future gas requirements, which shall be about 400 bcm by 2025, and about 500 bcm by 2030. In Dec 2019, it has commissioned a 56-inch gas pipeline the 'Power of Siberia' for importing gas from Arctic and Sub-Arctic gas fields in Western Russia. The through-put of gas is likely to reach 38 bcma by 2023. It is also in discussions with Russia for new pipelines from Sakhalin Region in its North and Altai Region in the West. It also has plans to expand the Central Asia trunk Pipeline from Turkmenistan. It has secured strategic equity interest in several LNG Liquefaction plants like LNG Canada in Kitimat BC in Western Canada, Arctic-1 LNG (Yamal) & Arctic-2 LNG (Gydan) in Russia and in the Rovuma LNG in Mozambique. By 2020, it plans to increase its Regasification capacity from 73 MTPA to 100 MTPA, enabling it to encash upon the availability of cheap LNG. It is also in discussions with the upcoming US LNG plants for contracting additional LNG. By 2030, its LNG demand could be anywhere around 100 MTPA.

3. India:

India is the fourth largest importer of LNG in the world. The country has a significant potential for economic growth. India began its LNG imports in 2004, when its first LNG receiving terminal was commissioned at Dahej, Gujarat. In 2019, about 55% of its gas demand was met by LNG. The LNG demand in India is price sensitive. In 2019, backed by soft prices in the Spot LNG markets, LNG imports grew by 7%.

Nearly 80% of India's energy demands are met by coal and oil. Gas comprises of only 6% in the energy basket. The country's gas demand is driven by government policies for sectoral gas allocations and pipeline expansions. The government has planned to increase the share of gas in its energy basket from 6% to 15% by 2024. In the past few years, there have been significant investment commitments for expanding its trunk pipeline network with the Federal government chipping in with Viability Gap Funding. It was introduced regulatory reforms to incentivise domestic gas exploration and production. In the last two years, it has awarded licences for about 138 Geographical Areas for City Gas Distribution (CGD), which envisages access to gas for about 70% of its population over the next 4-5 years. The CGD sector backed by the pipeline infrastructure under construction, shall be the pivot of growth in India's demand

As in April 2020, the country has an effective LNG import nameplate capacity of 33.3 MTPA and with about 63% utilization. At present about 33.2 MTPA Regasification capacity is under construction to support the demand for additional gas. India's LNG imports are likely to increase by about 17 – 20 MTPA by 2025 and by about 30 MTPA by 2030.

4. Taiwan:

Taiwan is the fifth largest importer of LNG and its imports are rising at a steady 3-4% p.a. It imported about 17 MTPA in 2018. It is expanding its import capacity to about 32 MTPA and its imports are likely to grow to 24-25 MTPA by 2030.

5. Bangladesh:

The country commissioned its first LNG import facility in 2018, a 500 mmscfd (about 4 MTPA) FSRU with 138,000 cum storage, off Moheshkhali island on a 15-year Build-Own-Operate-Transfer (BOOT). In 2019, it commissioned a similar FSRU in close vicinity of similar capacity. As its domestic production is declining, its dependence on LNG is likely to increase to 12-15 MTPA by 2030.

6. Indonesia:

The country was world's largest exporter of LNG till 2005. But since, its domestic consumption has outstripped its production. It supplies some pipeline gas to Singapore and Malaysia under long-term contractswhich shall expire by the end of 2025. At present, Indonesia consumes some part of its LNG production in its own archipelago islands to fulfill domestic demand. By 2030, Indonesia is likely to turn a net importer of LNG.

7. Malaysia:

Like Indonesia, the domestic gas production in Malaysia is slowly declining and its domestic demand is increasing. By 2030, it is likely to consume its entire LNG in its Archipelago islands and turn a net importer. It has acquired a 25% equity stake in Canada LNG to ensure adequate supplies for its fuel security and trade.

8. Pakistan:

The demand for gas has been growing at about 4% p.a., and its domestic production is static or declining. In 2018, it imported about 7 MTPA of LNG. It is pursuing an aggressive exploration policy. It s expected that its LNG demand may grow to about 10 -14 MTPA by 2030.

9. Vietnam:

Like other South Asian countries, Vietnam's domestic production is declining. The country has about 10 terminals in planning stage and imports could reach 8 – 10 MTPA by 2030.

10. Singapore:

It currently sources gas by pipelines from Malaysia and Indonesia and some LNG. In 2018, it imported about 3 MTPA. The countries entire power generation is on gas. In 2025, its pipeline supplies shall end and the country has decided to switch entirely to LNG. Its demand is likely to increase by another 5 MTPA by 2025, and 10 MTPA by 2030.

11. Philippines:

Like most South-east Asian countries, its domestic production is reducing, and it is likely to turn a net importer of about 2-3 MTPA by 2030. It has recently ordered its first RLNG facility, an FSRU.

7.6 LNG Supply: Capacity addition in Liquefaction and Shipping

The softening of prices have boosted the LNG trade. In 2019, LNG trade grew by by about 41 Million Tons or 13% over the trade in previous year In 2019. The growth needs to be supported by timely investment in Liquefaction and Shipping capacity.

7.6.1 LNG Capacity addition

In 2019, about 42.5 out of 101.3 MTPA capacity under construction has been completed. Further, new FIDs for global LNG Liquefaction capacity addition of 70.6 MTPA were achieved in 2019 as tabulated at Table 3.2.1 above and as under:

a) Golden Pass (US)	:	15.6 MTPA (with exemption from FTA restriction)
b) Sabine Pass Train 6 (US)	:	4.5 MTPA
c) Mozambique LNG	:	12.9 MTPA

d) Callacassieu Pass (US)	:	10.0 MTPA
e) Arctic LNG-2 (Russia)	:	19.8 MTPA
f) Nigeria Train 7	:	8.0 MTPA

The above capacity is likely to start producing from 2024 /25 onwards, and with this the fears of tight markets have been allayed till say 2025 -2030.

The LNG Liquefaction plants are capital intensive and the capital risk is shared by firm off-take agreements. The promoters of LNG Liquefaction plants in the USA, followed by LNG Canada, have ushered in a new trend of equity participation by off-takers, including traders, portfolio players and end users, in the capital structure of the investments. This trend of 'Affilliate Marketing' has helped in achieving the FIDs in time and in the award of the EPC contracts, a key milestone in project execution. In 2019, nearly 71% of the new FID volumes have been taken by equity participants as also illustrated in the following figure:

Fig-7.6.1: Investment in Liquefaction Facilities by Contract Types

(Source Shell LNG Outlook 2020 / IHS Markit)

'Equity off-take' or 'Affilliate Marketing' has emerged as a significant game changer for future growth of LNG Liquefaction capacity and also a key enabler for fulfilling the global demand at affordable prices and certainty of supplies in time.

7.6.2 LNG Shipping Outlook

As enumerated earlier, the entry of new shipyards for LNG shipbuilding in Korea, Japan and China, has brought in a significant shift in availability and the cost of LNG vessels. The impeccable safety record in LNG Shipping has also abetted to growing confidence in their capabilities and efficiency. The new propulsion systems from MAN (ME-GI) & Wartsila (XDF) have also ushered in lower fuel consumption and operating efficiencies.

The orderbooks and delivery schedules across the shipyards indicate that orderbooks had adequate LNG carriers, for Spot Trade (56 Nos) as well as for Long-term charters (62 Nos).

With limited scrapping, the fleet size is likey to grow to above 600 LNG carriers by 2020 (Reviera Maritime, 30th Dec 2019). In view of this, the availability of LNG Vessels is unlikely to remain a constraint till the year 2024.

Photograph copyrights of CPC Corporation, Taiwan

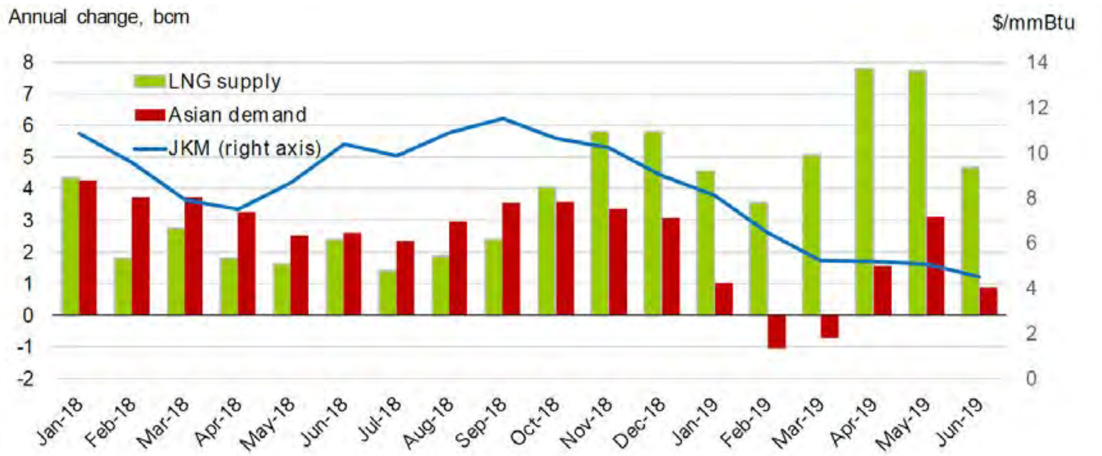
Chapter 8: LNG –Affordability

8.1 Pricing of LNG and its impact on consumption in low income countries

In order to sustain as a reliable fuel in the long-term, LNG has to be competitive with substitutes. The demand and its growth in the low income countries of South and South-east Asia are quite significant. However, its acceptance as a reliable energy source and growth in the low-income countries can sustain if it is 'affordable'.

For example, the Asian demand is highly price sensitive. It can be seen in Fig 8.1.1, that from Nov 2018 onwards, buoyed by the low prices of JKM below 10 $/mmbtu, supplies of LNG cargoes shot up in Asia.

Fig-8.1.1: Incremental LNG Demand &Supply and JKM Prices in Asian Markets (IHS Markit S&P Global Platts)



Source - OIES

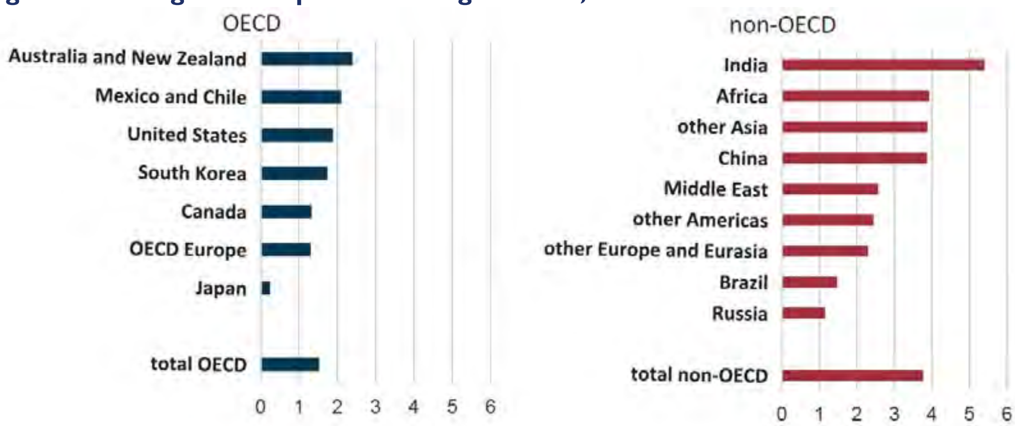
8.2: Key issues to be considered for affordability

The following issues need specific consideration for analysis of growth of LNG and its affordability,

8.2.1 The growth markets are Non-OECD countries

As per EIA, the GDP growth per capita is nearly two times in Non-OECD countries.

Fig-8.2.1: Average annual percent change in GDP, 2018 – 2050



(Source International Energy Outlook 2019, EIA)

As per the Fitch-IGU report as well, 80 to 90% demand increase is in Asia, primarily in India and China

8.2.2 Fear of gas burn-out

There is a growing fear that Gas as fuel may begin to fade out from 2030 or 2040 onwards, except from India & China. As per a Granthum Institute study, coal will be totally phased out by 2050, as per their High PV / Low EV scenario. They predict that gas would start declining from 2030.

In fact the Greenpeace Energy (R)evolution scenario 2015, which is a modelling simulation on '2 degrees C' Scenario predicts that gas may start declining from 2030 onwards. The Advance (R)evolution scenario predicts Gas in 2030 to be just 5% above 2012 consumption, in 2040 at 16% below 2012 consumption and in 2050 to just 7% of the 2012 consumption. Only India and China show resilience and demand sustains in these markets.

The Greenpeace projections are based on a popular forecast model and the consensus that Gas may begin to fade out from 2030-2040 with exception of India & China. The oil & Gas producing companies and economies may struggle to sustain the market share in the global energy basket.

The LNG demand projections by IEA in World Energy Outlook in the 'Sustainable Development' scenario is only 636 MTPA in 2040, about 15% less than their reference scenario, i.e., 'Stated Policy' scenario as mentioned in the table 7.2 above.

8.2.3 Per-capita income in the region

The wholesale gas prices vary across markets. They are low in countries with domestic production, and obviously higher in countries importing gas, by pipelines or as LNG. The wholesale gas prices have indicated convergence over the years. Yet, the Asian markets have significant variations, with Chinese Taipei, Japan, Korea and China at the higher end of the spectrum and Bangladesh, Pakistan at the lower end and India somewhere in between. Beyond a certain price, the gas may just not be affordable due to availability of cheaper substitutes or inability to pay. In context with the above, it is imperative that competitiveness of LNG can globally prevail only if it is accepted 'as an affordable fuel' with reliable supplies.

8.3 Affordability of LNG: The OIES study and key take-aways

The Oxford Institute of Energy Studies (OIES) has examined affordability of RLNG and published a Research paper, NG 142 (Claudio Steur). It has analysed the available historical data of CAPEX of LNG plants across the globe, gas costs prevailing in these countries, and likely shipping costs based on the industry data for prevailing efficient vessels. The LNG consumers have been segregated based on their per capita income as a benchmark for affordability. The data analysis indicates the likely cost at which LNG can be available and if the next lot of LNG Liquefaction plants can be competitive for the traditional four LNG Markets.

8.3.1 Data organization and key assumptions

The analysis has following steps:

1. Segregate LNG markets / clusters on per-capita income basis.

The LNG markets have been split in the following four clusters:

- High Income Markets of North West Europe(NWE High)
- High Income Japan-Korea-Taiwan- China (JKTC)
- Low income markets of North West Europe (NWE Low)
- Low income markets of South Asia , India-Pakistan-Bangladesh (IPB)

2. Estimate the energy prices for different markets

The key gas benchmark prices have been projected for 2025 using the data for the last 15 years as in the table below:

Table-8.3.1: Estimated energy benchmark prices

Energy Benchmarks - Gas/ LNG Prices- 01/25 ($/MMBtu)	
Brent $/bbl	$61.15
TTF	$7.29
JKM	$7.63
Henry Hub	$3.06
Cont EU Gas Price (LT contract)	$7.34
JKTC (LT contract)	$8.76
US LNG to NWE	$7.82
US LNG to JKTC	$9.13

(Source: OEIS)

3. Establish the price-appetite for these markets

The price appetitie for the LNG markets in the Low Income Markets, i.e. NWE & IPB has been assumed at 6 $/mmbtu. The price appetite for High Income NWE has been taken as 7.34 $/MMBTU (EU Gas Price index) and for JKTC as 8.76 $/mmbtu,i.e. JKTC LT Contract index.

4. Identify the potential LNG plants for FIDs in 2019 & 2020

Liquefaction facilities with FIDs in 2019 and on its verge were picked up in the following markets:
- Qatar LNG
- Mozambique LNG
- Russia – Arctic LNG-II and Sakhalin Expn
- Nigeria LNG
- USA Lower 24 LNG New plants & USA Old Plants (2011-2015)

5. Benchmark data for a recent Liquefaction plant

The available data of LNG Canada, which achieved FID in 2018, was taken as a nearest historical reference. FID data of LNG Canada, a Greenfield development, was used as reference for estimating the cost of LNG in three cost elements, i.e., Gas supply, Liquefaction and Shipping. The complexities for costs (geographical / locational difficulties, processing & removal of liquid/condensate/impurities, gas recoveries, utilities like consumptive power, water, steam, housing for manpower, CO2 treatment and sequestration etc) were also taken into account and weightage given for arriving at respective normative costs. In case of brownfield expansions, the cost is suitably discounted. Following Liquefaction costs emerged for different areas as in the figure below:

Fig-8.3.1: Liquefaction costs for different areas

Liquefaction Project Location	MTPA Capacity	$/tpa US$ 2018	$/mmBtu*
All Locations	490	946	$3.31
Remote / High Cost Locations	280	1,226	$4.29
Qatar	78	482	$1.69
USA Lower 48	61	660	$2.31
West Africa	31	1,084	$3.79
Russia / Arctic	33	1,292	$4.52
Australia	89	1,789	$6.26
Australia (excl Gorgon, Ichthys, Wheatstone, Prelude)	52	1,273	$4.46
FLNG	12	1,975	$6.91
FLNG (excl Prelude)	9	1,432	$5.01

Note: (*) Indicative $/mmBtu based on $3.50/mmBtu per $1000/tpa. Source: LNG Canada FID presentation.

(Source: OIES NG 142, Claudio Steur)

6. Benchmarking costs of gas resource in the respective countries

The gas costs have been analysed for every country.The supply costs have been assumed as 3.5 $/mmbtu per 1000 $/tpa of LNG plant at USD 2018. Such a benchmarking support the emerging numbers.

7. Projecting shipping costs in the target voyage routes

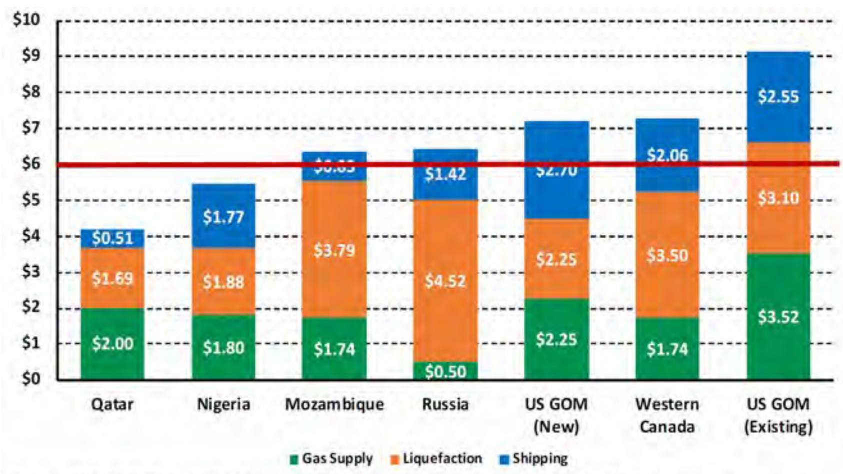
The shipping costs have been analysed for a 180,000 cm capacity with the latest propulsion systems, charter rates of 72,000 $/day, bunker fuel costs considering the distance and voyage time for a round trip, route, fee for Suez & Panama for supplies from every LNG facility to respective four markets as also the then IMO 2020 regulations for limiting sulphur below 0.5 ppm in bunker fuels.

8.3.3 Key findings on affordability in regions of different income segments

The cost of LNG from key upcoming locations worked outbelow 6 $/mmbtufrom Qatar and Nigeria, just above 6 $/mmbtu from Mozambique and Russia and are about 7 $/mmbtu from US GOM (New) and Western Canada.The affordability of different markets from source emerged as follows:

i) Low Income I-P-B: LNG supplies from Qatar and Nigeria were the most feasible for the IPB markets as in Figure below:

Fig-8.3.2: LNG Affordibility test ($/mmbtu) for Low Income Markets: I-P-B in 2025

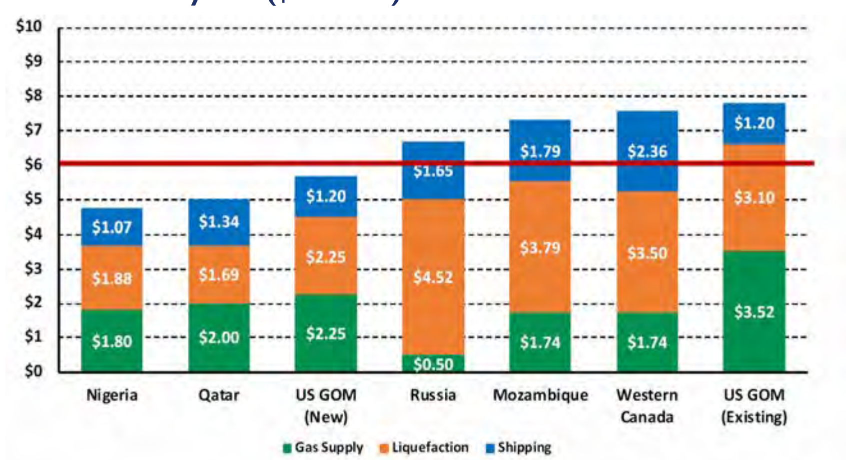


Source: EIA, ICIS Global LNG Markets, Forward Curves CME Group as of 14/12/18, SyEnergy estimates

(Source: OIES Paper NG 142)

ii) Low Income Market: North West Europe: LNG fromQatar, Nigeria, US GOM(New) were the affordable sources as in figure below:

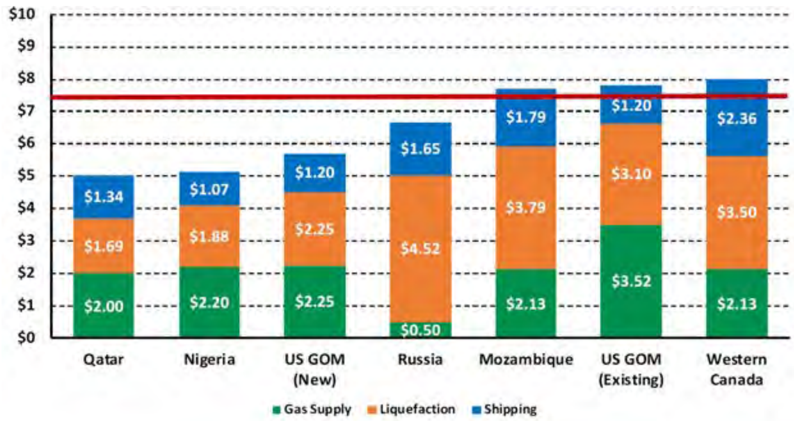
Fig-8.3.3: LNG Affordibility test ($/mmbtu) for Low Income Markets:NWE in 2025



(Source: OIES Paper NG 142)

iii) High Income NEW markets: LNG fromQatar, Nigeria, Russia and US GOM(New) were the affordable as in figure 8.3.4 below:

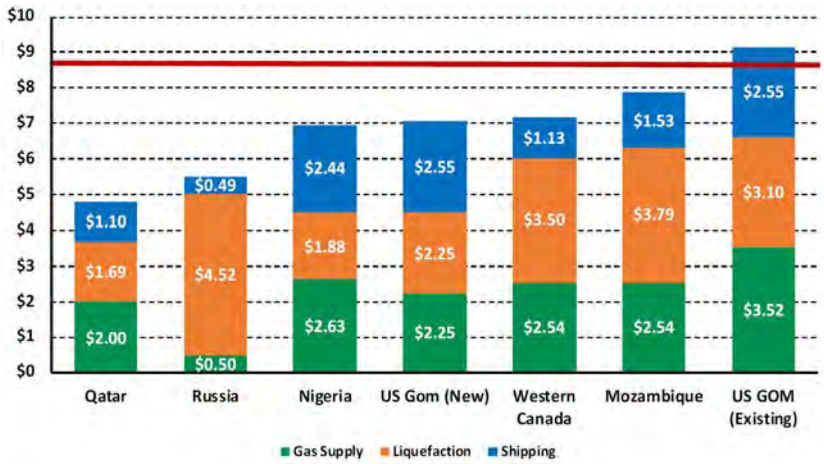
Fig-8.3.4: LNG Affordibility test ($/mmbtu) for High income NEW in 2025



(Source: OIES Paper NG 142)

iv) High Income Japan-Korea-Taipei-China: All sources except US GOM (Existing) emerged as affordable as in figure 8.3.5 below:

Fig-8.3.5: LNG Affordibility test ($ / mmbtu) forHigh Income Market (JKTC) in 2025



(Source: OIES)

8.3.4 Conclusions of the study

The analysis does support LNG Liquefaction and trade for High Income Europe and JKTM markets fromany source including US(GOM). The Low Income Europe with affordability at 6 $/mmbtu finds favourable suppliers from Qatar, Nigeria and US GOM (New). The India-Bangladesh- Pakistan cluster finds affordability only from Qatar and Nigeria. The Mozambique and Russian LNG, at a little over 6 $/ mmbtu, can become affordable with some cost cutting. A key observation is that the additional demand of I-P-B markets is only about 50-60 MTPA till 2025, which is less than 15% of the global LNG trade and appears feasible to be met from the affordable sources.

Kogas Jeju LNG Terminal – Courtesy of Kogas

Chapter 9: Key factors affecting growth of LNG Trade

9.1 Macroeconomic factors for LNG Demand

Growth in the LNG demand is expected to be provided by the Asian countries, particularly South Asia. With a large population, urbanization levels presently a third of the OECD countries, rising energy demand andneed for a clean fuel are likely to drive up the demand from South Asia.

9.2 'Affilliate Marketing' or 'Equity off-take' model to support fresh FID

The growth in supply would need more FIDs to be achieved over the next few years. The shortfall in demand is expected to be around200 – 300 MTPA till 2040. The 'Affiliate Marketing' or the 'Equity Offtake' models as seen last in the FID of LNG Canada in 2018, has bolstered the confidence of the sellers. Such support is likely to help achieve FIDs in future

9.3 Enhanced degree of dependability and acceptance of LNG

The investments in LNG Liquefaction capacities and certainty of production volumes have been key enablers in its acceptance in developing countries. Many countries are facing decline in their domestic gas production and LNG supplies fill the void. Many countries are expecting their domestic gas production to improve in future and look forward to LNG as a 'bridge' fuel. The nations which have already invested in gas transmission infrastructure find that LNG provides economic value in terms of the price arbitrage over substitute fuels in terms of heating value, as well as a more sustainable source compared to oil and gas.

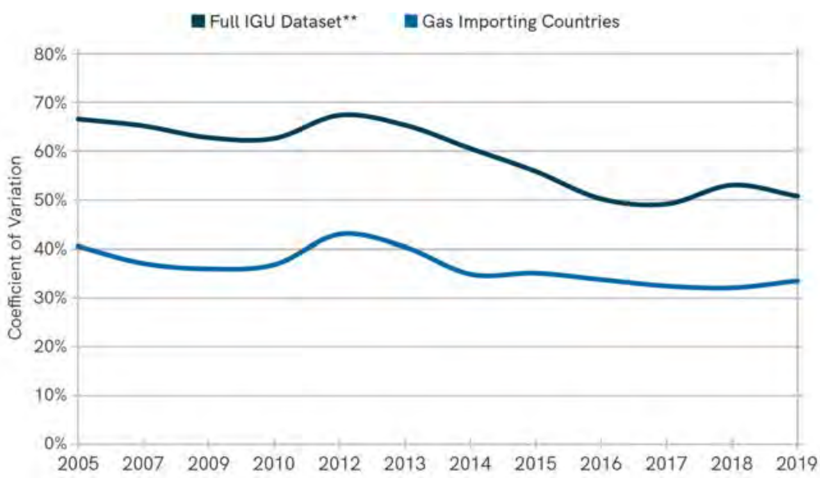
9.4 Increase in investments in mid-stream infrastructure

IEA has projected that the mid-stream investments, (including RLNG terminals and transmission and distribution pipelines) are currently at a high level with several major pipeline projects nearing completion.

9.5 Market trends: Price convergence

IGU has analysed the data of gas price formation mechanisms, average gas prices, gas volumes across 100 countries with subset data of share of imports. Utilising the standard deviations and the mean value, it has evaluated the coefficient of variance. The lower the coefficient of variance, higher is the price convergence. As per IGU analysis, wholesale gas prices in the gas importing countries indicate reduction in the coefficient of variance as in the figure below:

Fig-9.5.1: Price convergence for the Gas Importing Countries



(Source: IGU Wholesale Price Survey Report 2020)

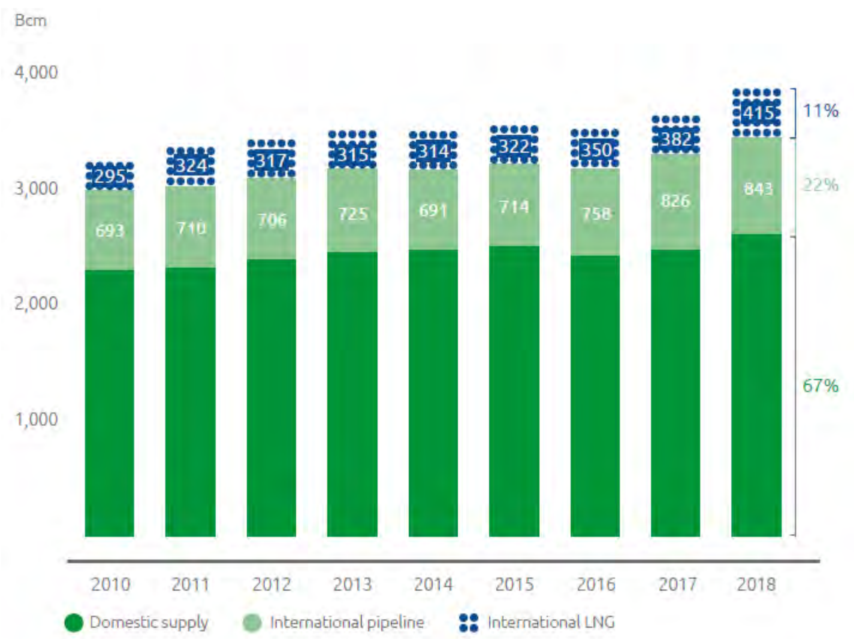
The above market trend augers well for LNG to be traded as a commodity.

9.6 Impact of trans-national lines under construction

A gas market that imports gas by Transnational Pipelines and also LNG, would first maximise the cheaper option to its capacity. Therefore, for the future gas imports for such markets, gas supplies from Trans-national Pipeline compete with LNG. However, laying of trans-national pipelines is a capital intensive project. Some of the pipeline projects are facing delays due to difficulties in land acquisition, difficult terrain and political conflicts.

For long distances, LNG exports are more flexible and reliable. In 2010, out of 988 bcm of international trade, a little over 70% was by pipelines, and in 2018, out of 1256 bcm of trade, about 841 bcm or approx 67% was by pipeline as in the figure below:

Figure -9.6.1: The share of domestic, transnational pipelines and LNG from 2010 to 2018:



Nevertheless, as discussed in detail at Para 6.6 above, some of the key pipelines under construction or expansion like Nord Stream 2 and TurkStream Expansion are likely to face delays in the face of political sanctions from the United States.

While the US sanctions have faced criticism from Germany, Slovak, Turkey, Bulgaria, and allies. However, another section of EU countries including Poland, Ukraine, Belarus etc are supporting the sanctions to marginalize the growing clout and monopoly of Russia on gas supplies to Europe. Their contention is that the Russian gas supplies could have been delivered by augmenting the pipeline infrastructure that passes through these countries for the existing supplies, which would have benefited these countries in the form of transit fees, and is being deprived deliberately by Russia.

The Nord Stream 2 is an ambitious project worth nearly $15 Billions and 90% of the pipeline is already completed. The compressor stations on the Russian despatch end and at the receiving end in Germany are already completed. The delay in pipeline can spur an LNG demand of upto 40 MTPA for Europe.

Shell LNG Station - Courtesy of Shell

PART – 2: Gas and RLNG Environment in BBINS REGION

Chapter 1: Gas and RLNG Environment in India

1.1 Key demographics of the energy sector

India is amongst the fastest growing economies across the globe. It ranked 5th in terms of nominal GDP and 3rd in terms of GDP by PPP (Purchasing Power Parity). Except for 2019-20, India's GDP growth rate was around 6-7 % since 2013. The per capita income is around 2200 USD, and falls in low middle income group. India is world's second largest producer of coal, cement, steel and food; and the third largest producer of electricity.

As per BP Statistical Review 2019, India is the second highest driver of the growth in World's primary energy. India's Primary Energy consumption in 2018 (excluding Biofuels) was 809.2 MTOE, dominated by Coal and Crude / Petroleum. Gas comprised only about 6% of the total primary energy consumption, as collated in the table below:

Table-1.1.1: India's Primary Energy Consumption 2018

Source	MTOE	Share (in %)
Coal	452	56
Crude / Petroleum	239	30
Gas	50	6
Nuclear	9	1
Hydropower	32	4
Renewables	27	3

Source - BP Statistical 2019

India's electricity sector is one of the most diversified sector amongst developing countries. Its per capita electricity consumption in 2018-19 was only 1181 kwhragainst global average of 2,674 kWhr. The country's per capita primary energy consumption is a third of the global average of 1.8 toe (tonnes oil equivalent). The low per capita energy consumption and its GDP growth reflect high potential for increase in its energy consumption in the coming years. While India is the third highest absolute producer of CO_2 emissions behind China and the USA, its per capita emissions are quite low. As per World Bank data of 2017, India's per capita CO_2 emissions was only 1.7 MT, way behind the USA (16.5 MT) and China (7.5 MT), and it ranks 158 amongst all countries in the world.

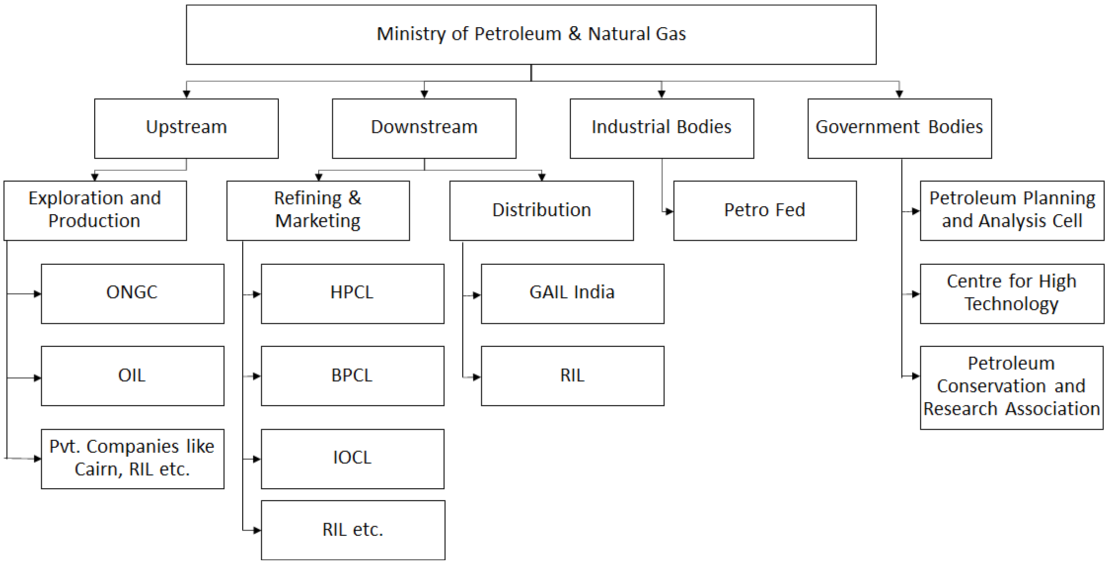
1.2 Organogram of the Hydro-carbon Sector

The Oil & Gas sector in India is regulated by the Government of India. The Ministry of Petroleum and Natural Gas (MoP&NG) is the administering ministry. The upstream policies are regulated by the Directorate General of Hydrocarbons (DGH) which is the key technological arm under the MoP&NG, and advises government on all policies related to E&P. The key upstream sector has several state-owned (ONGC, OIL etc) and privately owned (RIL, RIL-BP, Cairns, etc) E&P companies.

The downstream regulator is the Petroleum & Natural Gas Regulatory Board (PNGRB), set up by the government after enactment of the PNGRB Act 2006. Key oil refining & marketing companies are IOCL, BPCL, HPCL, RIL and some joint venture companies. Key Gas pipeline and distribution companies are GAIL India Ltd, Gujarat State Petroleum Corporation (GSPC), Reliance India Ltd, IOCL, BPCL & HPCL. After the thrust on City Gas Distribution (CGD), several private companies have entered in gas distribution and sales.

There are several bodies which advise the government on sectoral issues related to E&P, Marketing & Distribution, Planning &Pricing policy, Efficiency, Safety, Conservation and technology infusion. as illustrated in the figure below:

Fig1.2.1: Organogram of the Oil & Gas Sector



(Source:Ministry of Petroleum & Natural Gas)

1.3 Regulatory Environment and Government Policies

Background

Oil seepages were observed by Geological Survey of India as early as in 1865 while prospecting for coal. The first commercial oil well was dug at Digboi, Assam in 1989/1990 by the Assam Railway & Trading Company, which later led to the formation of the Assam Oil Company. A small refinery was set up in Margharita, Assam in 1991. In 1999, the Digboi Refinery was set up with a capacity of 500 barrel per day (bpd, which till date remains the oldest operating refinery in the world. Several private companies obtained concessions from the government to carry out geophysical exploration. The exploration, production, refining and marketing remained with the subsidiaries or jointly held subsidiaries of British Petroleum and Shell. The initial explorations were based on 'Torsion balance' , one of the earliest geophysical instrument for measurement of oil & gas in soil. From 1937, seismic surveys were introduced for exploration by these companies. This led to enhanced discoveries.

After attaining its independence in 1947, the Geological Survey of India along with the private companies (mainly Assam Oil Company, Indo Burmah Petroleum and Burmah Oil Company) continued the exploration and production while marketing was licensed to several private companies viz Burmah-Shell, Caltex and Esso. However, during 1955-56, the Indian government decided to adopt the Soviet model for its oil sector development by the Public Sector. In April 1956, the Government adopted a new Industrial Policy, and thereafter, the future development of Mineral Oil would be the sole and exclusive responsibility of the state. In August 1956, ONGC was formed to look after exploration and production. In 1959, an act of Parliament made ONGC a statutory body, as a public sector undertaking (PSU), under the administrative control of the Ministry to plan and implement programs for production of petroleum resources. In 1959, Oil India was incorporated with government acquiring one-third of the stocks from the Burmah Oil Company. In 1961 the government increased its stake to 50% and in 1981, it acquired the full ownership of the company. With this, the entire upstream came under full control of the PSUs, ONGC & OIL. Policy formulation in the oil & gas sector and their implementation effectively came under the Ministry of Petroleum & Natural Gas (MoP&NG).

Post the economic reforms in 1990s, new investments in various sectors in India like Power, Telecom, Insurance, Oil & Gas etc, were opened for the private sector. The government began systematic divestments from these sectors. For the exploration of oil & gas, an upstream regulator i.e. Directorate General of Hydrocarbons (DGH) was established in April 1993 under administrative control of MoP&NG through a Resolution by Government of India. The introduction of New Exploration Licensing

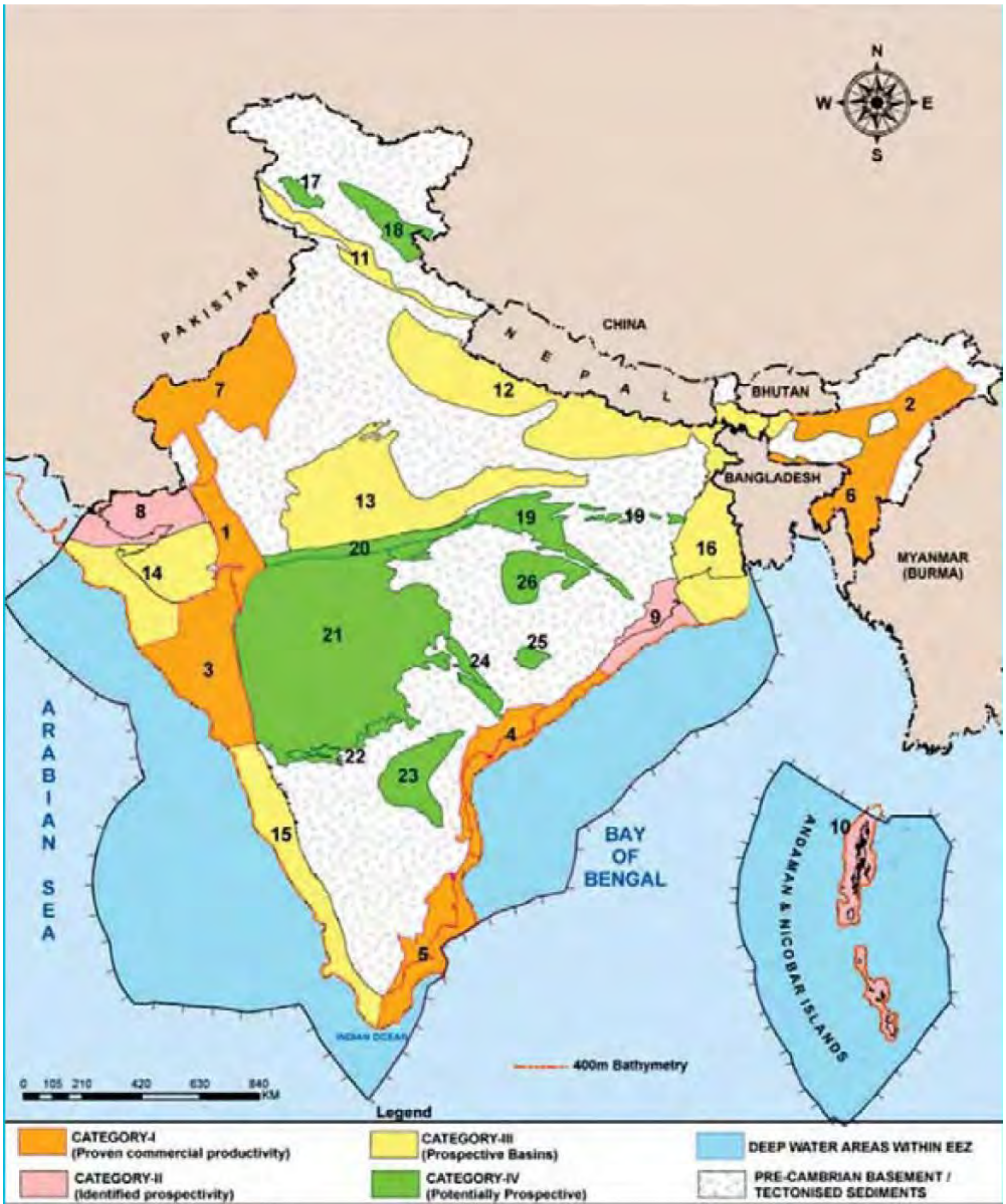
Policy (NELP) by Government of India in 1997-98, paved way for entry of licensees from Private sector in Upstream Oil & Gas sector.

1.3.1 India's sedimentary basins

India has 26 sedimentary basins spread over 3.36 million sq kms. Out of these, 1.63 million sq kms are on land and the rest is in shallow and deep waters..The shallow off-shore of upto 400m isobaths have an aerial extent of 0.41 sq kms, while the rest 1.32 million lie in deep waters above 400m isobaths.

The DGH has divided these basins in four categories. A map by DGH illustration the geographic boundaries of all the basins in these four categories, is reproduced in the figure below:

Fig:1.3.1: India's Sedimentary Basins



Category I	Category II	Category III	Category IV
1. Cambay Basin	8. Kutch Basin	11. Himalayan Foreland	17. Karewa Basin
2. Assam Shelf Basin	9. Mahanadi Basin	12. Ganga Basin	18. Spiti -Zanskar Basin
3. Mumbai Offshore Basin	10. Andaman-Nicobar Basin	13. Vindhyan Basin	19. Satpura-South Rewa-Damodar Basin
4. Krishna -Godavari Basin		14. Saurashtra Basin	20. Narmada Basin
5. Cauvery Basin		15. Kerala -Konkan -Lakshadweep Basin	21. Deccan Syneclise Basin
6. Assam-Arakan Fold Belt		16. Bengal Basin	22. Bhima -Kaladgi Basin
7. Rajasthan Basin			23. Cuddapah Basin
			24. Pranhita- Godavari Basin
			25. Bastar Basin
			26. Chhattisgarh Basin

(Soure: DGH)

Each category is illustrated in different colour These categories are: (Refer figure- illustrating these categories is as reproduced below)

Category-I: Basins with established discoveries and commercial production (amber colored).There are seven Category-I basins - Cambay, Assam Shelf, Bombay High, Assam Arakan , Krishna Godawari (KG) and Cauvery basins. As per DGH and the Oil companies, these basins produced about 33 Million MT of crude in 2019-20 as at Table -2 below.

Category-II: Basins with known hydrocarbon deposits considered geologically prospective (in pink). There are three Category-II basins, Kutch, Mahanadi and Andaman & Nicobar basins.

Category-III: Basins with prospective hydrocarbons shows (yellow colored). There are six such basins

Category-IV: Basins which may be potentially prospective based on analogy with similar basins in the world (in Green). These are ten basins.

The map also illustrates the maritime boundaries of the deep water blocks.

1.3.2 Upstream – Policies and regulations

Since its formation in 1993, DGH has been entrusted with several responsibilities like:

a. Implementation of the Exploration Licensing Policies, the New Exploration & Licensing Policy (NELP) followed by Hydrocarbon Exploration & Licensing Policy (HELP) from 2016 onwards

b. Matters concerning Production / Revenue Sharing Contracts for discovered fields and new exploration blocks

c. Promotion of investment in E&P Sector

d. Review and monitoring of E&P activities including reservoir performance of producing fields

e. DGH is also engaged in opening up of new unexplored areas for future exploration.

f. Development of non-conventional hydrocarbon energy sources like Coal Bed Methane (CBM) as also futuristic hydrocarbon energy resources like Gas Hydrates and Oil Shales.

Petroleum Exploration Licenses (PEL) for domestic exploration production of crude oil and natural gas were granted under the different regimes over a period of time as follows:

1. **Nomination Basis:** Petroleum Exploration License (PEL) were granted to National Oil Companies viz. Oil and Natural Gas Corporation Ltd (ONGC) and Oil India Ltd.(OIL) on nomination basis prior to implementation of NELP.

2. **Pre-NELP Discovered Field:** Petroleum Mining Lease (PML) was granted under small/medium size discovered field with Production Sharing Contract (PSCs) during 1991 to 1993 where operators of blocks are private companies and ONGC/OIL has the participating interest.

3. **Pre-NELP Exploration Blocks:** 28 Exploration Blocks are awarded to private companies between 1990 and prior to implementation of NELP where ONGC and OIL have the rights for participation in the block after hydrocarbon discoveries.

4. **New Exploration Licensing Policy (NELP) (1999 – 2015):** Exploration blocks were awarded to Indian, Private and foreign companies through international competitive bidding process. The National Oil Companies viz, ONGC and OIL also competed on equal footing. Nine rounds of competitive bidding were held and 254 blocks were awarded, out of which, 81 were Deep Water, 59 were Shallow water and 114 were Onland. A brief summary of NELP rounds is enclosed at Annexure -I

5. **New Policy Initiatives by the DGH for accelerating E&P activities (2015 onwards):** The crude oil production has seen a decline after peaking in 2011-12 (refer Table-2 above). In a major policy drive to give a boost to petroleum and hydrocarbon sector, the DGH / Government has unveiled a series of initiatives as follows:

- **Discovered Small Field (DSF) Policy (2015):** Under Discovered Small field Policy, Government has awarded 30 Contract areas based on Revenue Sharing Model in March, 2017. The next round with about 25 blocks has also been offered.

- **Hydrocarbon Exploration & Production Policy (HELP):** This policy replaced the NELP with four key features, changes in the NELP viz, uniform licence for oil, gas & CBM; Open acreage; revenue sharing (replacing the erstwhile profit-sharing after cost recovery), marketing and pricing freedom subject to a ceiling (lowest of the landed price of LNG (Liquefied Natural Gas), Fuel oil landed price, or a weighted average prices of a basket of imported fuels (30% coal, 30% naphtha & 40% fuel oil) for the past 4 quarters. Under the HELP, Government has awarded 94 Exploratory Blocks on Revenue Sharing basis till March 2020.

- **Formation of National Data Repository (NDR):** In 2017, a state-of-the-art repository with all the available geological data for the E&P (seismic, gravity, magnetic, spatial, well logs, etc) has been opened for companies interested in investing in oil & gas exploration.

- **Marketing and Pricing freedom for gas production:** Market oriented pricing introduced in 2016 by the Ministry of Petroleum and Natural Gas to incentivize gas production from Deepwater, Ultra Deepwater and High Pressure-High Temperature fields, Coal bed methane (CBM),

- **Other Initiatives:** Policies for Grant of Extension to the PSCs under Pre-NELP Exploration Blocks, Investor friendly reforms introduced for category-II & III basin, permitting exploration and exploitation of unconventional hydrocarbons.

  Policy-wise details of main policies have been enumerated and explained at Annexure -1.

1.3.3: Midstream and Downstream: Policies and Regulations

A) Background

The government also entered the mid and downstream sectors engaged in Refining & Marketing of petroleum products. In 1958, Indian Refineries and in 1959 Indian Oil Company (IOC) were set up as PSUs. These were merged in 1964 to form Indian Oil Corporation Ltd (IOCL). In 1974, the Acquisition of Undertaking Act (Esso Act) paved way for taking over all midstream and downstream operations the private sector oil companies. In 1974, the Esso Standard and Lube Oil and made a PSU named Hindustan Petroleum Corporation Limited (HPCL). This was followed by the acquisition of the Chevron-owned Caltex oil refinery and marketing in 1976 and its merger with HPCL in 1978. In 1976, mid & downstream operations of the Burmah Shell were acquired, and another PSU, Bharat Petroleum Corporation Ltd (BPCL) was formed. By 1978, all the private sector oil marketing companies were taken over and the entire value chain of Upstream, Midstream and Downstream of Petroleum and Natural gas sector was under Oil & Gas PSUs /National Oil Companies (NOC). In 1979, the Gujarat State Government set up GSPC as a State PSU for Petrochemicals. The company expanded in Gas Transmission & Marketing, and later in Exploration. In 1984, the Indian Government formed the Gas Authority of India Ltd (GAIL) for development of transmission and distribution of natural gas in the country.

As a part of the economic reforms, the government opened up the mid and downstream sector and private players like ESSAR and Reliance set up their refineries.

In 2006, Petroleum and Natural Gas Regulatory Board (PNGRB) Act provided for the establishment of an independent regulatory board (PNGRB) as a downstream regulator for ensuring competition & level playing field in the sector. The Board started functioning w.e.f. June 2007. PNGRB have formulated several regulations pertaining to above area.

B) Policies and Regulations: PNGRB

PNGRB Act 2006 provides for the establishment of an independent regulatory board (PNGRB) as a downstream regulator to regulate the activities of companies related to:

- Refining
- Processing
- Storage
- Transportation
- Distribution
- Marketing & Sale of petroleum products, Natural Gas and City Gas Distribution (CGD)

The various functions of PNGRB are to introduce regulations as under:

a. Protect interests of consumers by fostering fair trade & competition amongst entities

b. Register entities to:

  - Market notified petroleum, petroleum products and natural gas, subject to the contractual obligations of the Central Government,
  - Establish and operate LNG terminals

c. Authorize entities to:

  - Lay, build, operate or expand a common carrier
  - Lay, build, operate of expand city/local natural gas distribution Network
  - Declare pipelines as common carrier or contract carrier

d. Fix Transportation Rate for Common & Contract carriers

e. Define Pipeline Access Code

f. Define Safety standards

g. Define Affiliate Code of Conduct (for 'Arms-length relationship')

1.3.4: Key regulations notified by PNGRB

A) Natural gas pipelines

The various important regulations notified by PNGRB for Mid-Stream / Natural Gas Transmission / Pipelines (NG P/Ls) so far are as under:

a. Authorization of Entities for laying/ building/ operating or expanding NG P/Ls
The regulation stipulates that for Existing / Under-Operation NG P/Ls before the Appointed Day, NG P/Ls authorized by Central Govt. prior to Appointed Day do not require any authorization from Board. Fresh NG P/Ls after the Appointed Day, would require PNGRB's authorization. Proposals for new NG P/L can originate from any interested entity through an Expression of Interest (EoI) or suo-moto from PNGRB also. Authorization is granted on basis of competitive bidding process. Dedicated pipelines are exempted from these Regulation.

b. Network Access Code
The main objective of this regulation is to ensure Gas supply to any place from any place for any one at competitive cost on non-discriminatory basis. The Transporter has to allocate pipeline on common / contract carrier basis to various shippers on non-discriminatory basis.

c. Affiliate Code of Conduct for Entities Engaged in Marketing & Transportation of Natural gas
It defines the boundary between gas marketing activities and transportation activities by any entity who is engaged in both activities. The main objectives of the Code are to segregate costs associated with marketing & transportation activities, to ensure transporter to treat different shippers, including its own marketing activities, on a non-discriminate basis while allocating transportation capacities and ensure fair & competitive natural gas market.

d. Determination of Pipeline Tariff for Natural Gas Pipelines

The regulation defines the principles of determination of transportation tariff on reasonable return basis for Common/ Contract Carrier pipelines for which authorization has been given by Govt./ Regulator. Dedicated pipelines don't come under this regulation.

e. Declaration of Natural Gas Pipeline as Common Carrier or Contract carrier

The main objectives of this regulation are development of competitive natural gas markets and to avoid over investment by optimum utilization of infrastructure. The regulation describes the procedure for declaring the existing pipeline as common/contract carrier.

f. Determination Capacity of Petroleum, Petroleum Products and Natural Gas Pipelines

The regulation defines the procedure, parameters (constant & variable) and frequency of declaration of pipeline capacity in MMSCMD for natural gas by the entity. Capacity determination is based on selected Software Package & Flow Equation approved by Board.

B) City Gas Distribution (CGD) Sector

In the overall interest of the consumers and to ensure fair allocations of CGD Networks to licensees in a fair manner, PNGRB has introduced the following Regulations:

i. Determination of Network Tariff: dated 19.03.2008(GSR – 197 E)

ii. Exclusivity for City Gas or local nature Gas distribution: (GSR – 198 E)

iii. Authorising Entities to lay, build, operate or expand City / local Gas (19-03-2008)

iv. Tech Standards and Specifications including safety standards for City Gas – 2008

v. Regulation for quality of service - 2008

vi. Regulations for Access Code for CGD – 2011

vii. Regulations for integrity Management System for CGD / local Gas Distributor network – 2013

viii. Regulation for determining capacity of City or local Gas Distribution – 2015.

Salient features of Regulations for Midstream (Pipelines) and Downstream (CGD sector) are enclosed at **Annexure –II**

1.4. Reserves, Production, Gas allocation, Pricing & Pipeline Tariffs

1.4.1 Oil and Natural Gas reserves:

As illustrated in Fig 1 above, India has about 3.36 Million sq kms of sedimentary basins. As per BP Statistical Review 2019, India's Proven Reserves are 1.3 tcm. As per the Annual Report for 2017-18, of MoP&NG, these basins have about 3.8 tcm of 'Initial gas-In-place Reserves', the 'Balance Recoverable Reserves' are about 1.233 tcm (refer Table 1.4.1 below).

Table1.4.1 2India's Oil & Gas Reserves

	Initial In-Place			Ultimate Reserves			Balance Recoverable Reserves		
	Oil (MMT)	Gas (BCM)	O+OEG (MMT)	Oil (MMT)	Gas (BCM)	O+OEG (MMT)	Oil (MMT)	Gas (BCM)	O+OEG (MMT)
ONGC	5,009	2,204	7,213	1,433	1,249	2,683	431	560	992
OIL	806	384	1,140	252	217	440	79	125	187
Pvt/JV	1,081	1,246	2,327	234	738	972	84	548	633
Total	6,896	3,834	10,680	1,919	2,204	4,095	594	1,233	1,812

O+OEG: Oil and Oil Equivalent of Gas

(Source Annual Report 2017-18, MoP&NG)

Almost 70% of India's gas production is from the oil and gas fields of Western Offshore basins (Bombay High and Cambay basins). Rest is scattered across the Eastern off-shore (Krishna-Godawari and Cauvery basins) and the North-east (Assam-Arakan basin).

The Krishna-Godawari (KG) and Cauvery basins are in Deep / Ultra-deep waters. Besides, these reserves are bearing High temperature & high pressure zones. The cost of production from these difficult fields are higher as compared to Western Offshore or Assam-Arakan reserves. To encourage investment and production, the Government / DGH has introduced pricing freedom with a ceiling.

The domestic oil production of all sources for the past decade is given in the box below.

Domestic Oil Production:

As per DGH, Oil Companies and other sources, (refer table 1.4.3 below) oil production from all sources peaked at 38.1 MMT in FY 2011-12 and has gradually declined to 32.2 MMT in 2019-20.

Indigenous Crude oil production

Indigenous crude oil production (In Million MT)

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20(P)
PSU companies											
ONGC	22.8	22.5	21.8	20.5	20.4	20.8	21.1	20.9	20.8	19.6	19.2
OIL	3.5	3.6	3.8	3.7	3.5	3.4	3.2	3.3	3.4	3.3	3.1
PSU total	**26.3**	**26.1**	**25.6**	**24.2**	**23.9**	**24.2**	**24.3**	**24.1**	**24.2**	**22.9**	**22.4**
JVC & Private											
JVC/ Private	5.1	9.5	10.3	11.5	12.0	11.7	11.2	10.4	9.9	9.6	8.2
Total crude oil	**31.4**	**35.6**	**35.9**	**35.7**	**35.9**	**35.9**	**35.5**	**34.5**	**34.0**	**32.5**	**30.5**
Condensate	2.0	2.1	2.2	2.2	1.9	1.6	1.4	1.5	1.6	1.7	1.6
Total (Crude + Condesate)	**33.4**	**37.7**	**38.1**	**37.9**	**37.8**	**37.5**	**36.9**	**36.0**	**35.7**	**34.2**	**32.2**

(Source: Oil Companies and DGH; P - Provisional)

1.4.2 Unconventional Gas reserves

A) Coal Bed Methane (CBM):

CBM is an unconventional source of gas, mostly methane, which is adsorbed in the coal itself. As India has significant reserves of coal, the presence of CBM held bright prospects. As per the geological estimates, India has about 2.6 TCM (92 TCF) of Prognosticated CBM reserves spread over ten states. The majority of prospective areas for the CBM exist along with the coal bearing areas in the Damodar valley and Sone valley. The East, North and South Raniganj coal fields , Jharia Coalfields, East and West Bokaro Coalfields in the Damodar valley, and, Sonhat and East and West Suhagpur fields in the Sone valley have rich CBM reserves. As per the AR for 2017-18 of MoP&N, 'Gas Initial in place'(GIIP) reserves of about 280 BCM, and Recoverable reserves of about 108.2 BCM have been established, as illustrated in the table below:

Table 1.4.2: India's Recoverable CBM Reserves

State	Block name	Operator	GIIP (BCM)	Recoverable Reserves (BCM)
Jharkhand	BK-CBM-2001/1	ONGC	30.182	3.68
	NK-CBM-2001/1	ONGC	9.529	1.46
	Jharia	ONGC	14.61	3.04
Madhya Pradesh	SP(E)-CBM-2001/1	RIL	47.855	16.7
	SP(W)-CBM-2001/1	RIL	55.501	15.44
West Bengal	RG(E)-CBM-2001/1	EOL	60.881	28.12
	Raniganj North	ONGC	7.43	1.86
	Raniganj South	GEECL	54.368	37.94
Total			**280.357**	**108.24**

(Source Annual Report 2017-18, MoP&NG)

To plan and implement exploitation and production of CBM, DGH and Central Mine Planning and Design Institue (CMPDI) Ranchi interacted together and carved out the blocks which can be explored. In 1997, the Government brought out a Coal Bed Methane Policy to promote the exploration and production. This was followed by other policy initiatives like extension of exploration phases (2007), pricing freedom (2011), grant of exploration rights to Coal India Ltd and its Subsidiaries over the coal bearing areas for which they already held mining lease (2015), the HELP which permitted exploration for all kinds of hydrocarbons (conventional or unconventional) within the allotted block, and a policy framework for exploration and production of unconventional hydrocarbons in existing acreages under the existing Production Sharing Contracts.

So far the government has awarded 30 CBM blocks via 'bidding' route, 2 blocks on 'nomination' basis and one block through Foreign Investment Promotion Board (FIPB). As per DGH, out of 62.4 TCF of Prognosticated reserves of these blocks, about 9.9 TCF of gas-in-place reserves have already been established. The Gondwana sediments of eastern India hold the bulk of coal reserves and also the CBM Blocks. CBM production has commenced from three blocks, Raniganj (South) by Great Eastern Energy Corporation Ltd (GEECL), Raniganj (East) by Essar Oil & Gas and Suhagpur (West) by Reliance Industries Ltd.

B) Shale Gas:

As per DGH, prospective Shale oil and gas formations exist in 6 basins, Cambay, KG, Cauvery, Gangetic, Assam & Gondwana. Following agencies have analysed the resource basins and probable reserves of Shale Oil & Gas:

a. Schlumberger: 300 to 2100 TCF of Shale Gas resource.
b. EIA, USA (2011): 290 TCF in four onland basins ((Cambay, Damodar, KG & Cauvery).
c. EIA, USA (2013): 584 TCF of gas and 87 Billion Barrels Oil in the above four basins.
d. ONGC: 187.5 TCF of Shale gas in 5 basins (Cambay, Ganga, Assam, KG & Cauvery).
e. CMPDI: 45 TCF OF Shale gas in 6 sub-basins (Jharia, Bokaro, NorthKaranpura, South Karanpura, Raniganj and Sohagpur).
f. USGS under MoU between DoS & MoPNG (2011): Technical recoverable 6.1 TCF in three onland basins (Cambay, KG & Cauvery). Later in 2014, USGS further identified 62 Million Barrels of Shale oil in the Cambay basin and more than 3.7 TCF of Technically recoverable gas from the tight sandstone reservoirs of KG and Cambay basin.

In 2013, India launched an ambitious program to explore its Shale oil & gas resources by permitting ONGC and Oil India to carry out exploration of 175 blocks in three phases of three years each. 50 blocks were identified in the first phase. ONGC took up 26 wells in the first phase in three basins. About a quarter of these wells were exclusively for shale gas & oil while the other were overlapping with conventional exploration. The overlapping wells were drilled deeper to explore shales for oil and gas.

It has been recently reported that Indian shales are younger and tertiary. Unlike the brittle formations in the 'Permian' basin in the USA, the geology of India's shales were found to be elastic in nature with more clay content, and not conducive to 'fracking' for successful release of the trapped gas resource. ONGC has suspended its exploration program and has requested the government / DGH for re-assessment of the shale reserves.

In addition to the above geological reverses, environmental and social issues also need to be addressed. In a paper on challenges and prospects of shale gas in India by Advisor, Niti Aayog, several pre-requisites including assessment of environmental (baseline data for water quality of aquifers, contamination, disposal of propants) and social issues (incentives to address the conflict as regards the agricultural pursuits of land owners) need to be addressed. It has also been recommended that the available geological data with NDR for the prospective shale basins may be studied thoroughly while pursuing shale gas exploration.

C) Bio Gas:

It is estimated that India has potential for 62 MMT of Bio-gas from the Municipal solid and bio-degradable wastes. The government has launched a program called 'SATAT' (Sustainable Alternative towards Affordable Transportation) to tap this potential. The biological wastes is processed to produce methane gas, which will be compressed and utilised as 'Compressed Bio Gas' (CBG). The government has invited Expression of Interest for awarding 5000 CBG plants.

As per MoP&NG AR 2018-19, the domestic gas production had peaked in 2010-11 to 146 mmscmd. Thereafter, the offshore production from the KG D-6 fields drastically declined and domestic gas supplies came down to about 85 MMSCMD by 2016-17 (refer table below).

Table 1.4.4: India's Gas Production from 2011-12 to 2017-18

(in MMSCM)

State/Region	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18 (P)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(a) Onshore:							
Andhra Pradesh	1364	1249	1171	541	619	868	959
Arunachal Pradesh	40	41	41	34	30	28	30
Assam	2905	2910	2868	2958	3025	3128	3219
Gujarat	2173	2032	1657	1527	1490	1580	1607
Rajasthan	590	685	982	1178	1338	1277	1442
Tamil Nadu	1285	1206	1304	1192	1011	983	1207
Tripura	644	647	822	1140	1332	1430	1440
Jharkhand (CBM)	4	3	3	2	2	3	4
Madhya Pradesh (CBM)	2	3	6	2	1	6	200
West Bengal (CBM)	79	101	156	224	389	555	531
Total (a)	**9084**	**8877**	**9012**	**8797**	**9237**	**9858**	**10639**
of which							
OIL	2633	2639	2626	2722	2838	2937	2881
ONGC	5751	5447	5316	4752	4770	5205	5638
PSC Regime	699	791	1069	1323	1629	1717	2119
(b) Offshore:							
ONGC	17565	18102	17968	17272	16406	16883	17791
PSC Regime	20910	13700	8428	7589	6605	5155	4219
Total (b)	**38475**	**31802**	**26395**	**24861**	**23012**	**22038**	**22011**
Grand Total (a+b)	**47559**	**40679**	**35407**	**33657**	**32249**	**31897**	**32649**

Note: Total may not tally due to rounding off CBM: Coal Bed Methane P: Provisional
Source: Oil & Natural Gas Corporation Ltd., Oil India Ltd. and DGH

(Source: MoPNG)

1.4.4 Gas Allocation

Domestic Gas Allocation Policy:

The gas sector took off with discovery of substantial oil & gas reserves on the western off-shore, (Bombay High and the Cambay Basin) in the seventies. The distribution of gas was in isolated pockets of North-east, Gujarat and Mumbai. A trunk pipeline (Hazira-Vijaipur-Jagdishpur or the HVJ pipeline) from Hazira (Gujarat) to Jagdishpur (near Allahabad, UP) was planned with some anchor customers, primarily fertilizers and power. Prior to nineties, almost the entire gas production was by the NOCs, ONGC & OIL from regulated fields allocated by the government. As such, its pricing was also as per 'assessed' pricing policy or the 'Adminitered Price Mechanism' laid down by the government. The gas distribution was as per allocations by the government as per the prevailing policies. The government's priority always remained Fertilizers and Power followed by others like steel, glass, ceramics and other industrial consumers.

In nineties and the following decade of the NELP-era, many private entities also entered in the exploration and production of gas. The pricing of this gas was as per the terms of NELP, and the government intervention remained. However, gas allocations remained with the government. To encourage investment in gas exploration and production, the government introduced pricing and marketing freedom with some restrictions (Refer 1.3.2 (v) above). The gas pricing would attract a ceiling as decided every six months by the government. For the six-month period from 1st April 2020 to 30th Sep 2020, the ceiling price is 5.61 $/mmbtu on GCV basis.

The priority of allocation was revised from time to time in line with interventions by Supreme Court or High Courts. In nineties, the Supreme Court intervened for protection of environmental harm to Taj and special allocation was reserved for the Taj Trapezium Zone. In subsequent years, the Supreme Court came down heavily on automotive pollution in New Delhi and Mumbai. In 1998, Supreme Court took cognizance of the environmental impact of automotive emissions on public health and directed conversion of all non-CNG public transport to CNG in Delhi and later in Mumbai. This led to the City Gas Distribution gaining its initial footholds. After a Court's judgement in 2014, the government came out with policy for priority allocations for the CGD sector for supply to Domestic Households and CNG for automobiles. As per the policy, upto 110% requirement of the CNG & Domestic PNG (Piped Natural gas) is to be met from supplies under Administered Price Mechanism (APM), PMT & the Non-APM gas. The industrial and commercial PNG can be met from market gas, i.e., Term / Spot RLNG (Re-gassified LNG) or domestic gas from new fields which have been freed from the APM regime and can be procured by the bidding route.

Gas allocation from KG D-6 gas fields

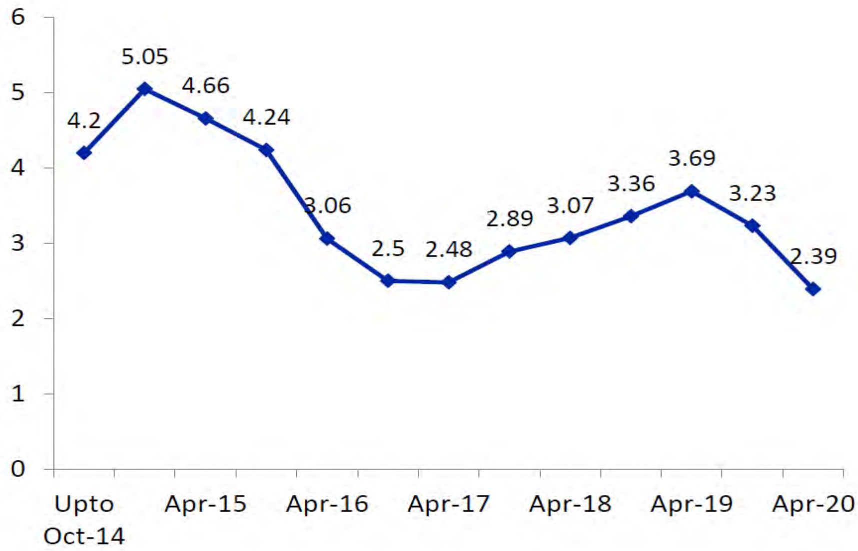
In 2005, the discovery of huge gas reserves in the KG D-6 gas fields, allocated to RIL under the PSC regime, triggered phenomenal interest amongst consumers. However, there were dispute amongst the promoters as regards the distribution and pricing as per PSC. The Supreme Court ruled that natural gas is a sovereign asset and the Government has the right for its utilization. The production of KG D-6 was planned to reach over 90 MMSCMD. Allocations from KG D-6 to the existing consumers were enhanced and broad allocations were set aside for different sectors, with Fertilizer and then the Power sector securing maximum share. Many promoters came forward alongwith lenders to install gas-based power projects. The government made a policy to allocate gas to Power Plants on 'First-come-first serve' on their commissioning. About 15 GW of Gas-based power generation capacity was taken up for implementation by different promoters. However, after touching peak of about 60-63 MMSCMD in 2011, the production drastically declined to about 15-18 MCMD in 2013, leaving the power plants stranded with no other domestic gas.

1.4.5 Pricing

A) Administered Price Mechanism

Gas pricing has remained under Government's purview. As per the prevailing 'Domestic natural gas Pricing Guidelines 2014' by MoP&NG (refer Annexure III.) , beginning Oct 2014, the domestic gas pricing for all gas supplies under the Administered Price Mechanisms from Nominated and Pre-NELP gas fields is being done on the basis of weighted average domestic price indices of four main gas consuming economies, Henry Hub of USA, Alberta Reference of Canada, NBP of UK and Domestic gas price of USSR. The PPAC collect and maintain the data based on which prices are revised upwards or downwards. With effect from 1st April, the domestic gas prices are at 2.39$/mmbtu are at historical lowest, in this pricing regime beginning Oct 2014, as in the trend displayed in the figure below:

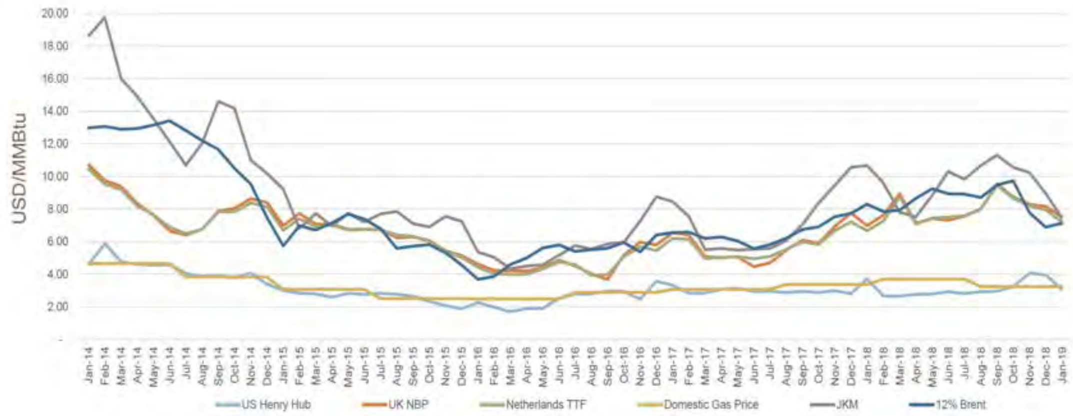
Fig 1.4.1: Trend of domestic gas pricing (in \$/mmbtu) as per Pricing Orders from Oct 2014



(Source: PPAC / ICRA)

The reason for low prices lies in the methodology for calculating the prices as per new gas pricing guidelines of 2014 by the Government, linking the same to the weighted average of the four international hub prices. Other than gas prices at NBP in UK, the domestic gas prices in Russia, Alberta Reference in Canada and Henry Hub in US are quite low. The new gas pricing guidelines for domestic gas have therefore resulted in significant reduction in gas prices. The following figure shows the trend of India's Domestic gas with other key gas price markers including 12% Brent. It may be noted in Fig below, that NBP-UK, Dutch-TTF are close to 12% Brent, while, Japan-Korea Marker (JKM) slightly lags, albeit a dollar or so on the higher side of the 12% Brent.

Fig 1.4.2.: Correlation showing Indian Domestic Gas Prices with Henry Hub, NBP, TTF , JKM & 12% Brent



B) Pricing mechanism of new fields

The pricing of gas from the NELP and Post-NELP blocks, and the Government's intervention in pricing came in for a lot of criticism. It was felt that there is no incentive to produce gas from difficult or remote or very small blocks. The government therefore introduced the following reforms in permitting pricing freedom subject to a ceiling for new domestic gas production:

- 2015-16: Discovered Small Field Policy & Pricing Freedom for Deep water, Ultradeep water, High Pressure & High Temperature fields. The existing price ceiling from 1st April to 30th Sep 2020 for Deep water, Ultra Deep, High Pressure & high temperature gas is 5.61 \$/mmbtu

- 2016-17: Pricing Guidelines were introduced by Ministry of Petroleum and Natural gas for Difficult Gas fields. Tthe existing pricing from 1st April 2020 is about 8.43 \$/mmbtu

- 2017-18: The MoP&NG introduced pricing Freedom for CBM Blocks and Policy reforms for review of PSCs. The CBM gas from three ONGC blocks in Jharkhand were bid out between 5.77 to 6.12 $/mmbtu in 2018
- 2018-19: Policy for Enhanced Recovery Fields

Presently the petroleum products including gas are outside the ambit of GST. The natural gas / RLNG are taxed as per the prevailing tax regimes in the respective states of its production as well as consumption. There has been a long-pending demand that like coal, gas may be brought in the GST. It may not be easy as the petroleum products contribute significantly to the revenue of the states. However, to begin with, the government is considering bringing natural gas under the ambit of GST.

C) Term LNG Pricing

The pricing of 'Long-term' (or Term) LNG is based on negotiated prices with the suppliers. The key supplier of Term LNG to Petronet India is Qatar Gas. The Pricing of Qatar LNG in India has been in $/ mmbtu. The Sale Purchase Agreement (SPA) has been re-negotiated in 2015-16 for better terms. Pricing has been benchmarked at 12.6% of Crude oil. The crude oil benchmark has been revised to three-month average of Brent crude from earlier 60-month moving average of Japan Crude Cocktail (JCC) price. There is small mark-up of 0.5 $/mmbtu. In 2017, the term contract for the Petronet's supplies from Exxon-Mobil's Gorgon LNG has been re-negotiated. The pricing is revised to 13.9% of Brent from 14.5% of JCC on Delivery Ex-Ship basis.

As per industry sources, the global trend of benchmarking LNG with Crude is however giving way to share of Gas-on-Gas contracts, as enumerated in Part 1 of this report.

D) Pricing of Spot LNG

A few LNG 'Spot' cargoes become available due to various reasons like surplus production, defaults by the buyers of term LNG or surplus with the LNG marketing companies or portfolio players. The spot prices are dependent on the supply-demand dynamics and have high volatility. Due to the economic slowdown post- COVID 19, Spot cargoes were reportedly available at throwaway prices, at even sub-2-3 $/mmbtu DES.

1.4.6 Pipeline Transportation Tariffs

The pipeline transportation tariffs are determined as per the Regulations by the regulator, PNGRB. The regulator award the pipeline based on a transparent bidding system which inter-alia considers the tariffs. As per the prevailing norm, Pipeline Tariffs are Zone-based, each zone being 300 kms. The last Zone shall be 300 kms or less. The prevailing tariffs can be referred in the table below:

Table 1.4.5: Gas Pipeline Transportation Tariffs (Industry Sources)

Sl. No.	Pipeline	Owner	Zonal tariff in Rs/MMBtu				
			Z1	Z2	Z3	Z4	Z5
1	HVJ (Old P/L)	GAIL	19.83	22.48	25.10	27.70	N/A
2	DVPL/GREP Upgradation	GAIL	42.46	48.14	53.76	59.32	N/A
3	Integrated HVJ	GAIL	19.83	36.86	45.38	49.64	N/A
4	DUPL-DPPL	GAIL	29.55	39.85	N/A	N/A	N/A
5	Dabhol-Bangalore	GAIL	45.37	45.41	45.44	N/A	N/A
6	JHBDPL	GAIL	63.44	63.50	N/A	N/A	N/A
7	Dadri-Bawana-Nangal	GAIL	14.04	14.06	N/A	N/A	N/A
8	Chainsa-Jhajjar-Hissar	GAIL	7.85	N/A	N/A	N/A	N/A
9	GAIL KG Basin Network	GAIL	16.14	N/A	N/A	N/A	N/A
10	East-West P/L	PIL	65.50	75.33	78.65	79.77	80.15
11	GSPL HP Grid	GSPL	33.15	34.84	34.86	N/A	N/A
12	GSPL LP Grid	GSPL	4.08	N/A	N/A	N/A	N/A

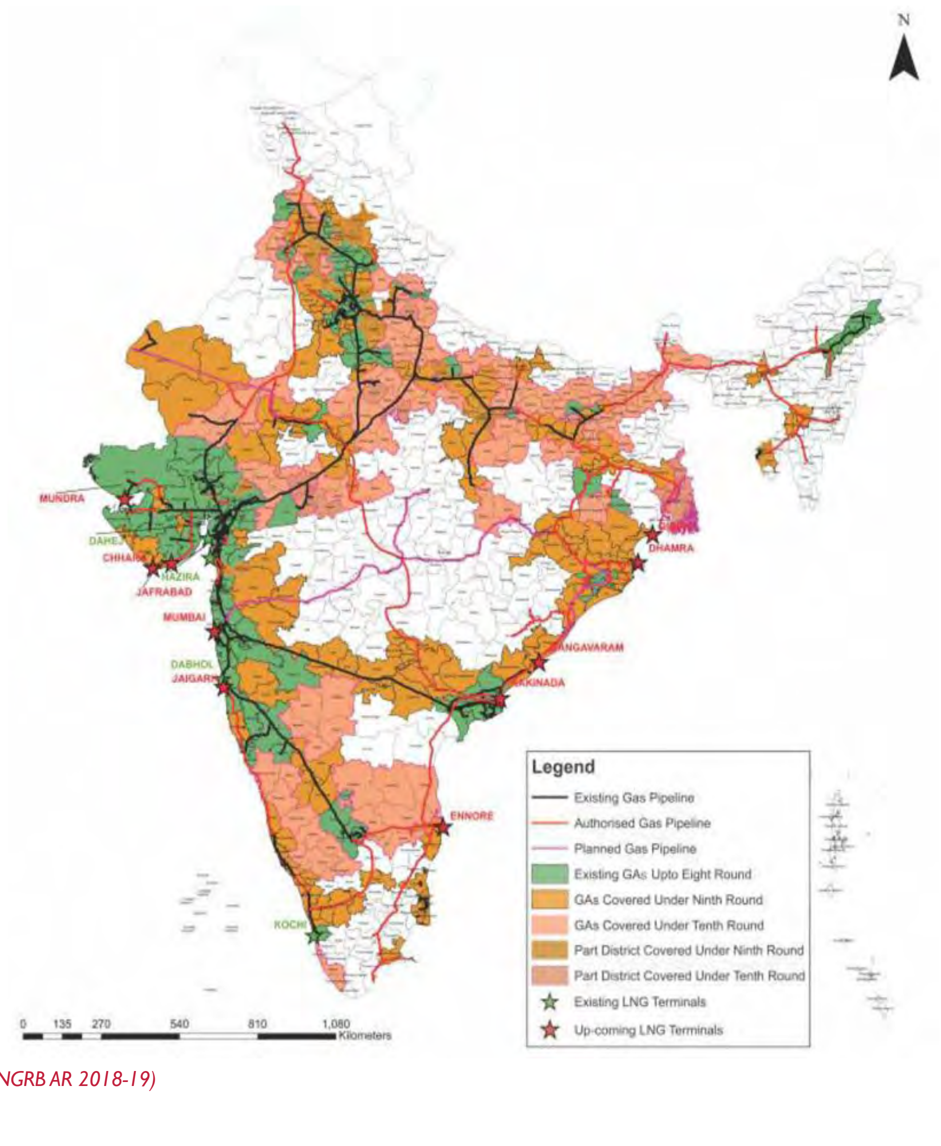
As per the existing regulations, if the gas traverses across two pipelines or more, the applicable tariff of each pipeline has to be borne by the consumer. Further, due to increase of capital costs in laying the pipelines, the newly laid pipelines would have higher tariffs. This leads to higher tariffs and energy costs incurred by consumers using two gas pipelines or more. Besides, as the pipeline network is being expanded on a Pan-India basis, it is likely that the consumers at the last mile and sourcing gas by utilizing multiple pipelines end up with higher cost of landed gas. This leads to loss of competitive advantage for industries or commercial entities in a distant zones or using multiple pipelines. Hence, there is a growing demand for rationalization of tariffs on a 'postalised' or 'unified' basis. In unified / postalized regime, the consumers in nearby zones would attract higher tariffs when compared to 'zonalised' basis. The other issue is the distribution of the realized tariffs amongst pipeline entities in a fair and remunerative manner so as to ensure the returns on investments for them. A consultative paper to review the norms of Tariff fixation and consider 'unified' Tariffs was released by PNGRB seeking comments from stakeholders and consumers.

1.5 Gas Infrastructure & Supplies

1.5.1 Key gas pipelines

At present, the RLNG and Gas trunk pipeline network and key consumers are in the western and northern part of the country. In the past ten years, several pipelines have been awarded by PNGRB under its regulations. The figure below gives an overview of the key Pipelines, RLNG Facilities and the Geographic Areas

Fig 1.5.1: Gas Pipelines, RLNG Terminals and Geographic Areas under development



(Source: PNGRB AR 2018-19)

A) Gas Pipelines: Existing and under construction / expansion

The country has an existing trunk pipeline network of nearly 17,000 kms. This includes about 4,000 kms of partly commissioned capacity of pipelines, balance works being in advanced stage of construction. A list of these pipelines alongwith their technical details such as length, size, flow capacity and utilization as compiled by PPAC is as as tabulated below:

Table 1.5.1: Salient data about Gas pipeline network as on 01.04.2019

Network/Region	Entity	Length (Kms)	Design capacity (mmscmd)	Pipeline size	Average flow 2018-19 (P) (mmscmd)	Capacity utilisation in 2018-19 (P)
Hazira-Vijaipur-Jagdishpur Pipeline/Gas rehabilitation and expansion project pipeline/Dahej-Vijaipur Pipeline & spur/ Vijaipur-Dadri Pipeline	GAIL	4554	53	36"	29.52	56%
DVPL-GREP upgradation (DVPL-II & VDPL)	GAIL	1385	54	48"	35.92	67%
Chhainsa-Jhajjar-Hissar Pipeline (CJPL) including spur lines *	GAIL	310	5	36" /16"	1.01	20%
Dahej-Uran-Panvel Pipeline (DUPL/ DPPL) including spur lines	GAIL	928	20	30"/18"	13.94	70%
Dadri- Bawana-Nangal Pipeline (DBPL)	GAIL	852	31	36"/30"/ 24"/18"	5.49	18%
Dabhol-Bengaluru Pipeline (Including spur)	GAIL	1116	16	36"/4"	1.27	8%
Kochi-Koottanad-Bengaluru-Mangalore (Phase-1)	GAIL	48	6	16"/4"	2.29	38%
Tripura (Agartala)	GAIL	60	2	12"	1.30	55%
Gujarat	GAIL	685	9	24"/16"/12"	4.37	49%
Rajasthan	GAIL	151	2	12"	1.35	57%
Mumbai (Uran-Thal-Usar & Trombay-RCF)	GAIL	131	7	26"	6.43	91%
KG Basin	GAIL	884	16	18"	5.40	34%
Cauvery Basin	GAIL	306	9	18"	3.25	38%
East- West Pipeline	RGTIL	1480	67	48"	19.44	29%
Shahdol-Phulpur Pipeline	RGPL	304	4	16"	0.90	26%
GSPL network	GSPL	2692	43	Assorted	34.57	80%
Assam network^	AGCL, DNPL	297	3	Assorted	1.92	69%
Dadri-Panipat	IOCL	140	10	30"/10"	5.02	53%
Total		**16324**	**320**			

Note:

*CJPL and DBPL pipelines are the extensions of DVPL-II / VDPL.

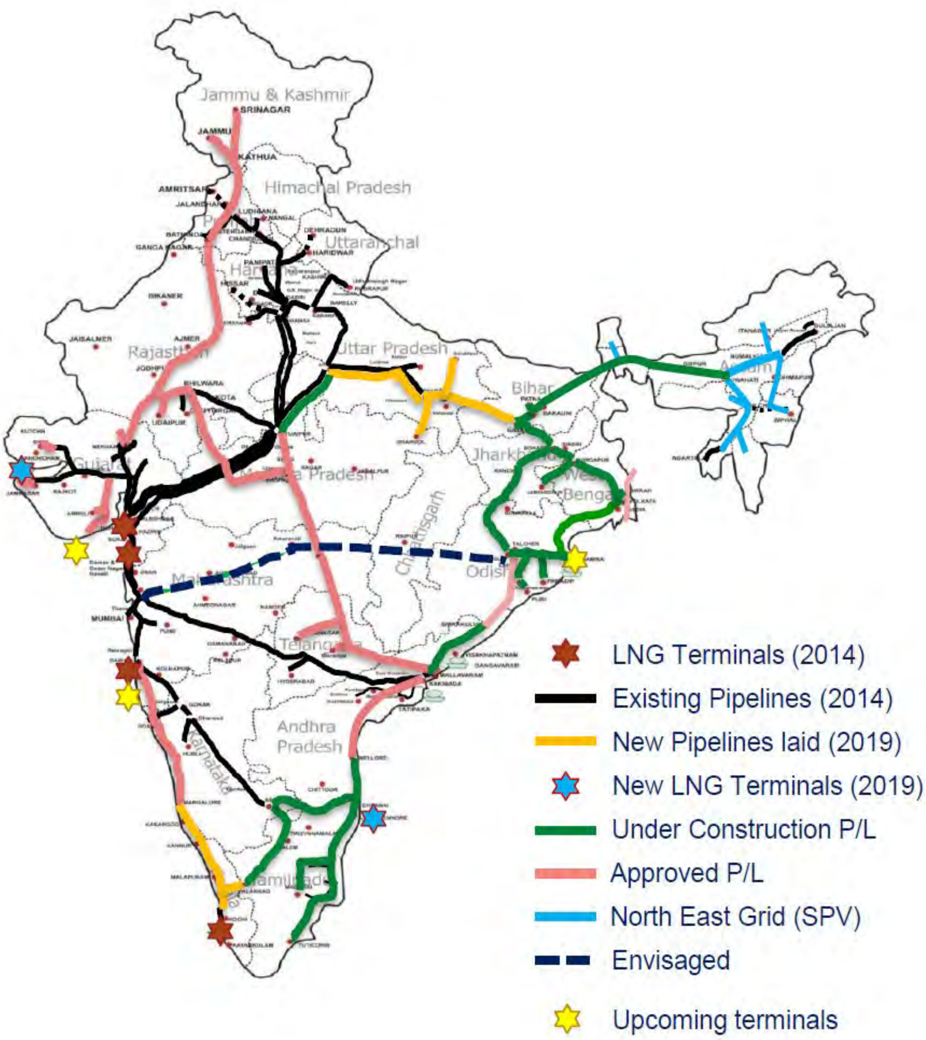
^Excludes CGD pipeline network

Source PPAC, Pipeline Operating Companies

PNGRB has been successfully awarding authorizations of many pipelines following transparent bidding process. Nearly 15,000 km of trunk pipelines are under construction and as per PNGRB, these lines are to be commissioned by 2022. The details of operational and partly commissioned natural gas pipelines as per PNGRB are at **Annexure IV A & IVB** respectively.

As a part of its commitment to increase the share of gas in India's Primary Energy basket from existing 6% to 15%, the GoI has taken several policy decisions. These initiatives support establishing adequate pipeline network under 'One nation, One grid' programme on one hand and establishing CGD networks for reaching the maximum population across the country's geography. It is planned to connect upcoming RLNG terminals with country-wide development of trunk pipelines and local distribution network under CGD. As a support measure, the government has also committed Viability Gap Funding (VGF) for financing the expansion of gas pipeline infrastructure in regions which do not provide fiscal incentives to investors to lay new pipelines. GAIL and GSPL, the pioneer gas pipeline companies have been joined by RIL, IOCL and other interested players including promoters of RLNG terminals to provide a healthy gas infrastructure to cover the majority of Industrial, Commercial and Domestic consumers. The following figure. brings out the a visual depiction of the trunk pipeline network along with the RLNG terminals.

Fig 1.5.2. Map of commissioned and under - construction pipelines and key terminals



(Source: GAIL)

It can be seen that the present pipeline infrastructure and the commissioned capacities are primarily concentrated in Western and Northern India, as depicted in black colored firm lines in the above figure.. However, for the upcoming RLNG terminals on the east, trunk pipelines are also under construction in the eastern and southern coastal areas. As per data compiled by GAIL, about Rs 92,000 Cr of investment is envisaged for these pipelines. GAIL is executing 6500 kms of pipelines on its own and another 2500 kms along with its JVs.

The key pipelines under construction connecting different geographic regions of India are as follows:

a) West-North: The e four key pipelines, which will connect northern states to RLNG terminals in the west and the national pipeline grid along with salient details are as follows:

Table 1.5.1a: Status of Pipelines under execution connecting West – North regions

Sl	Pipeline	Owner	Capacity (MMSCMD)	Length (KMs)	Completed Length	Original Schedule	Revised Schedule	States Covered
1	Mehsana-Bhatinda	GSPL	77	2052	340	30.5.15	31.03.20	Gujarat, Punjab, Rajasthan, Haryana
2	Chainsa-Hisar	GAIL	35	455	310	31.1.11	30.09.20	Haryana
3	Dadri-Bawana-Nangal	GAIL	31	886	816	31.01.11	31.08.20	UP, Punjab, Haryana, Delhi, Uttarakhand
4	Bhatinda-Jammu-Srinagar	GSPL	42	725	102	1.12.17	Under Review	Punjab, Jammu & Kashmir

(Source: PNGRB)

b) East & North-East: The 'Urja Ganga Yojana' and 'Indradhanush Yojana' comprise of multiple sections, details of which have been explained separately below at 'e'. These projects have been provided with VGF from the Government. The Kanai Chata – Srirampur line terminates very close to the Bangladesh border:

Table1.5.1b: Status of Pipelines under execution connecting East with North-East regions

Sl No	Pipeline	Owner	Capacity (MMSCMD)	Length (KMs)	Completed Length	Original Schedule	Revised Schedule	States Covered
1	Urja Ganga Yojana (JHBDPL) In multiple sections, details below	GAIL	16	3306	850	In Phases	In Phases upto 28.2.21	UP, Bihar, WB, Assam, Jharkhand & Orissa
2	Indradhanush (In multiple sections, details below)	GAIL JV	16			In phases	In Phases by 28.02.21	WB, Sikkim, Assam, Meghalaya, Tripura, Arunachal, Nagaland, Mizoram
3	Kanai Chhata-Srirampur	H-Energy	19	317	-	-	31.07.22	WB

c) East– Central – West: This pipeline will evacuate gas of ONGC & GSPC from KG Basin

Table 1.5.1c: Status of Pipelines under execution connecting East, Central and West regions

Sl No	Pipeline	Owner	Capacity (MMSCMD)	Length (KMs)	Completed Length	Original Schedule	Revised Schedule	States Covered
1	Mallavaram-Bhopal-Vijaipur-Bhilwara	GSPL	76.25	2042	-	31.12.17	31.03.20	AP, Telangana, MP, Rajasthan

(Source: PNGRB)

d) West- South: These pipelines will evacuate Gas from RLNG Terminals at Dabhol & Jaigarh and connect it to the southern region and the Kochi – Kottanad- Mangalore – Bangalore pipeline

Table 1.5.1d: Status of Pipelines under execution connecting West – South regions (Source: PNGRB)

Sl No	Pipeline	Owner	Capacity	Length	Completed	Original Schedule	Revised Sachedule	States Covered
					Length			
			(MMSCMD)	(Kms)	(Kms)			
1	Dabhol-Bangalore	GAIL	16	1414	1098	28.02.13	31.12.20	Maharashtra, Goa Karnataka,
2	Jaigarh-Mangalore	H-Energy	17	749	-	28.06.17	Time Extn under consideration	Maharashtra, Goa, Karnataka

e) South: These pipelines will serve the customer the Kochi and Ennore terminals.

Table 1.5.1e: Status of Pipelines under execution connecting various regions in South (Source: PNGRB)

Sl No	Pipeline	Owner	Capacity (MMSCMD)	Length (kms)	Completed (kms)	Original	Revised	States Covered
1	Kochi-Koottanad-Bangalore-Mangalore	GAIL	16	1104	138	28.02.19	28.2.22	Kerala, Karnataka, Tamil Nadu
2	Ennore -Tuticorin	IOCL	84.7	1385	22.6	9.12.18	28.02.21	Tamil Nadu, Karnataka
3	Ennore-Nellore	GTIL	36	430	2.12.14	2.12.14	30.04.20	Tamil Nadu, AP
4	Kakinada-Vizag-Srikakulam	GAIL JV	90	391	--	16.07.14	Under Review	Andhra Pradesh
5	Kakinada-Vijaywada-Nellore	IMC	22.5	667	-	-	31.08.21	Andhra Pradesh
6	Srikakulam - Angul	GAIL	6.65	690	-	31.07.22	31.07.22	Andhra, Orissa.

Two important pipeline projects, 'Urja Ganga' and 'Indra Dhanush' are ambitious project which aim to extend penetration of gas in the Indo-Gangetic Plain covering five populated states, UP, Bihar, West

Bengal, Jharkhand & Orissa. Detils of these projects are:

i) Urja Ganga Yojana: This pipeline project of 3,381 kms, comprises of multiple pipeline sections, and a part of which has been completed. This pipeline network will cover all the industrial commercial and domestic belts in east and north-east. Details are as follows:

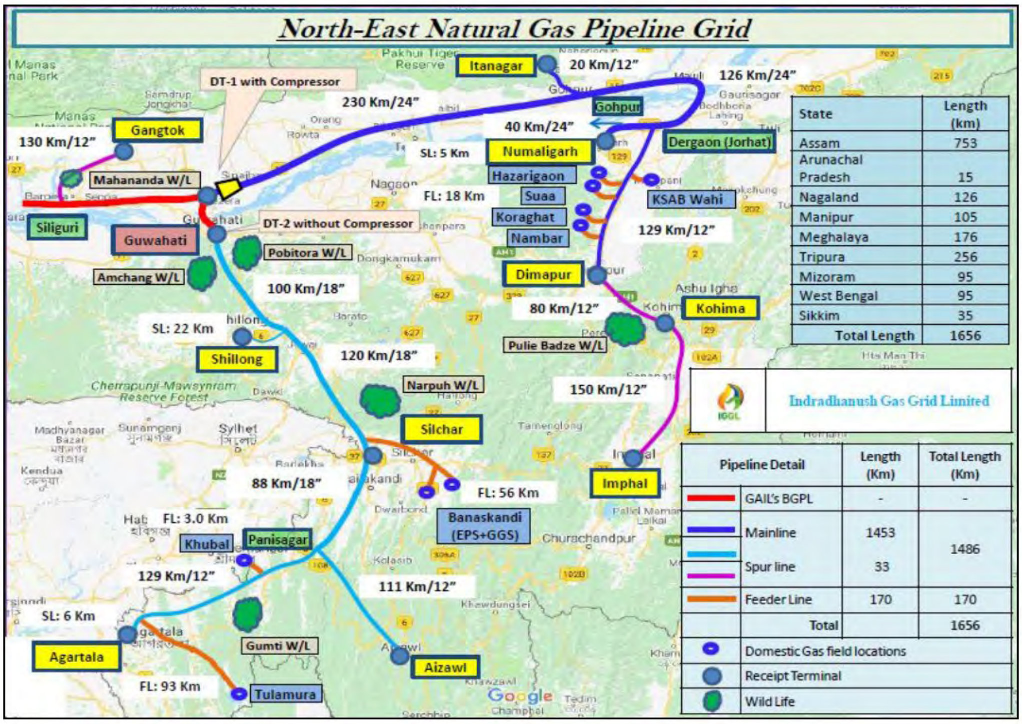
Table1.5.2: The Urja Ganga Project details

Sl.	Pipeline Name	Length (Km)	State covered	Sch. Completion
1	Jagdishpur Haldia Pipeline- Section 1	750	Uttar Pradesh	Completed
			Bihar	
2	Dhamra-Angul Pipeline Project (Section-2A) (400 Km)	400	Odisha	Completion progressively by Dec'2020
3	Dobhi-Durgapur Pipeline Project (Section-2B)*	500	Bihar	
			Jharkhand	
			West Bengal	
4	Bokaro- Angul Pipeline Project (Section-3A)	667	Jharkhand	
			Odisha	
5	Durgapur- Haldia Pipeline Project (Section-3B)*	335	West Bengal	
6	Barauni-Guwahati Pipeline project (As part of JHBDPL)*	729	Bihar	Completion by Dec'2021

(Source GAIL)

ii) Indradhanush Gas: North-East Gas Pipeline Grid: (Completion by Dec 2022): The grid connects all the eight states of north east as in the figure below:

Fig 1.5.3: Indradhanush – The Northe-East Natural Gas Pipeline Grid



(Source – GAIL)

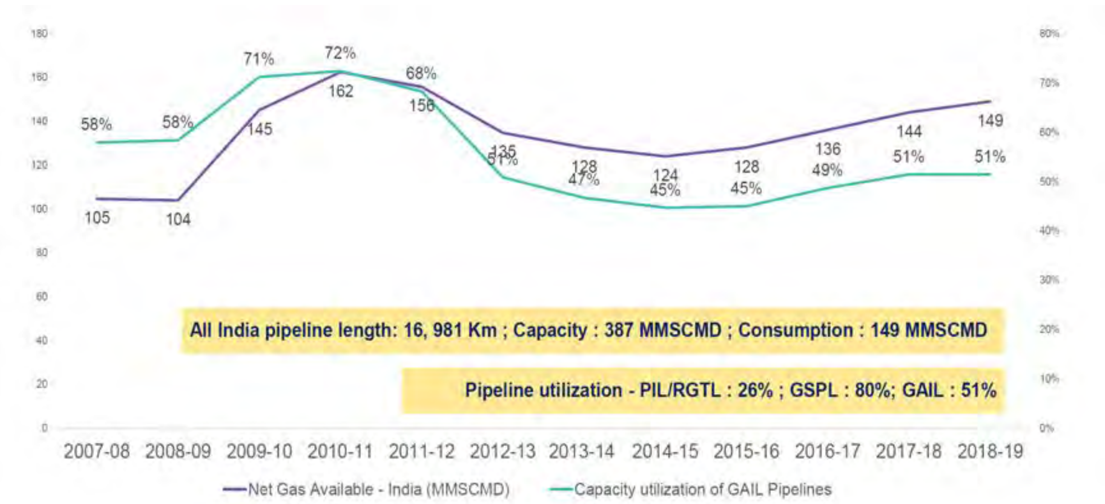
The total investment is about Rs 9265 Cr out of which, about 60% (Rs 5559 Cr) is as Viability Gap Funding (VGF) by the GoI. The grid will also help in connecting nearly 8-9 new gas fields in the North-East to the rest of the country.

This grid will also support development of CGD infrastructure and pave way for industrialization and entrepreneurship in this region. Above all, this grid has an initial capacity of 16 mmscmd and can be scaled up. Above all, this network has the potential to be connected to Myanmar and Bangladesh. This is of importance as the major on-shore producing gas fields in Bangladesh are in the Sylhet division in North-West, barely 110 kms from Silchar in Assam, India.

B) Pipeline Utilization

The existing Pipeline network is not adequately utilized. The pipeline utilization of GAIL's pipelines in 2018-19 was only 51%, down from 72% in 2011-12 as in the figure below ;.

Fig 1.5.4: Capacity Utilization of GAIL's Pipelines from 2007-08 to 2018-19

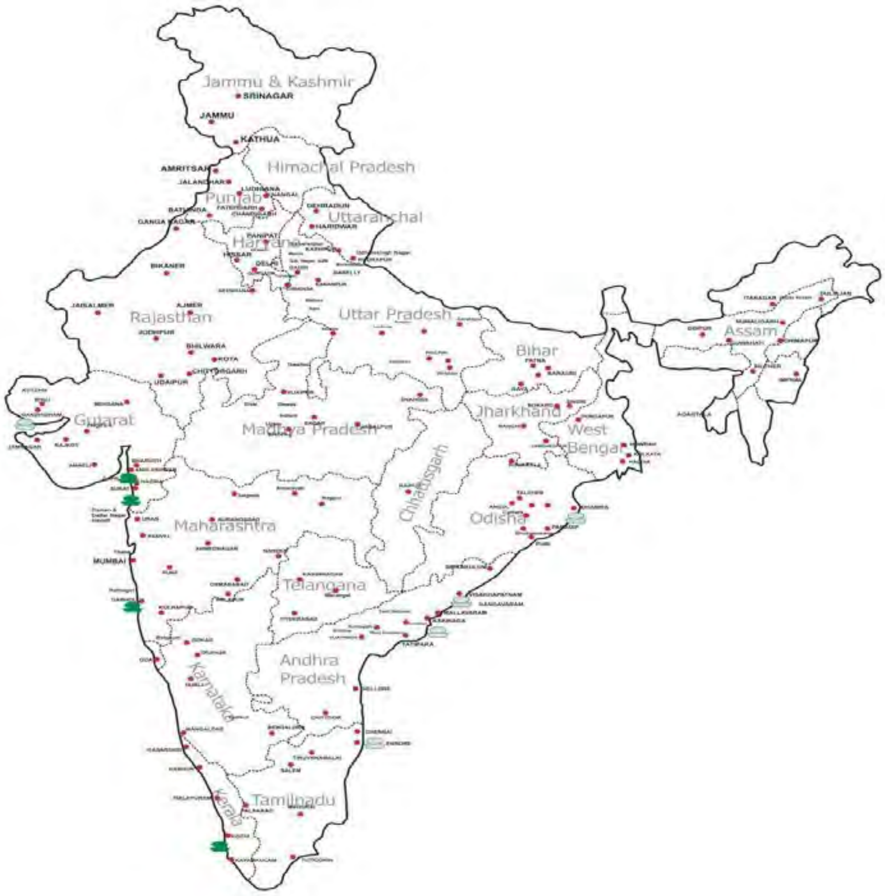


GSPL with utilization at 80% has been supported by its CGD and Industrial sector. PIL/RGTIL have less utilization due to the fall in production from KG D-6 basin and sub-par utilization of its East-West pipeline. GAIL's trunk pipelines are mainly in the West and North, and low demand from power sector which could not find buyers on RLNG based power, its pipeline utilization have come down. While spare capacity augers well for the economy and consumers, it is a loss to the pipeline owners as their tariffs are based at high levels of utilization.

1.5.2 LNG Receiving Terminals (RLNG)

In the late 90s, the shortfall in meeting demand led to the formation of Petronet LNG Ltd (PLL) with equity participation from the NOCs. The first LNG receiving terminal was installed at Dahej and the first cargo was received in 2004. Subsequently, in 2005, another LNG terminal was installed at Hazira near Surat by Shell and Total. Subsequently, Kochi and Dabhol terminals were also commissioned. To meet the growing demand, many other terminals were planned. The following Fig1.5.5 Maps all the existing and planned RLNG terminals

Fig1.5.5: India's RLNG Terminals: Existing and Under Constn / Planned

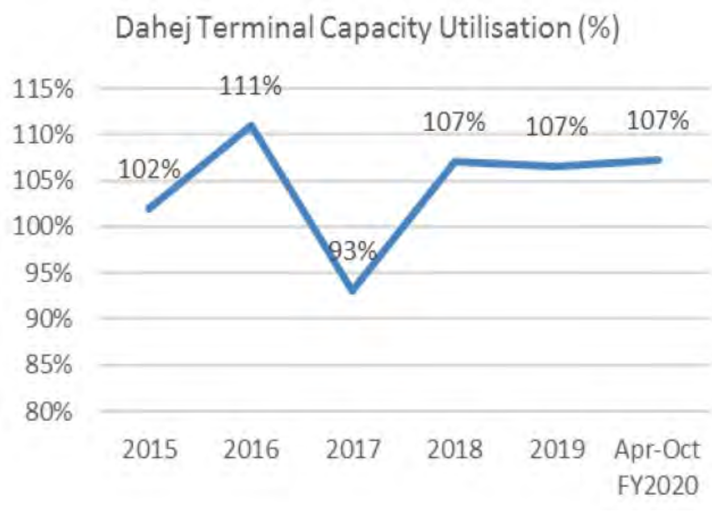


A) Existing RLNG Terminals

i) PLL-Dahej (Petronet LNG Limited) (17.5 mtpa)

The terminal has a current nameplate capacity of 17.5 MTPA. Expansion to a capacity of 20.0 MTPA is expected to be completed in 2023. PLL has a Long-term agreement with Qatar's RasGas for 7.5 MTPA. In 2015, PLL has renegotiated the pricing and other terms in 2015. Almost the entire capacity is booked by GAIL, IOCL, GSPC and others. The capacity utilization has been very high, exceeding 100% in some years, as below:

Fig 1.5.6a: Hazira Terminal: Capacity utilization (%)



ii) HLL – Hazira (5 MTPA)

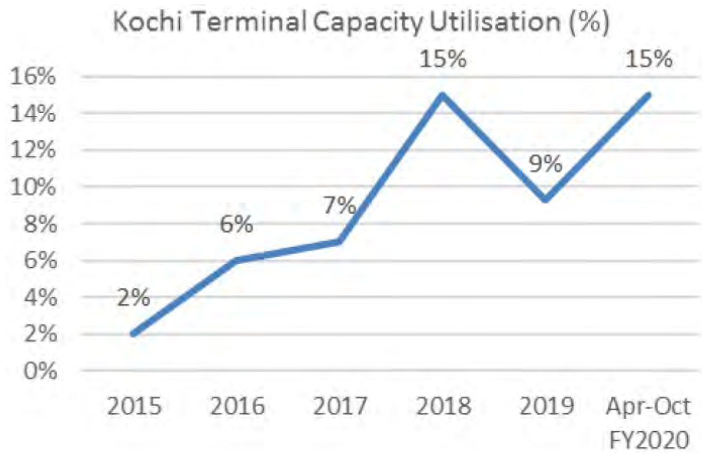
The second terminal of the country was set up by Shell with part equity participation by Total. However, Total has relinquished its equity in favour of Shell. The capacity is envisaged for expansion by another 5 MTPA. The terminal operates on short-term basis and also processes spots volumes. The terminal is connected to GSPL, HVJ, DUPL and the East-West pipeline, and this adds to its strategic location. After initial struggle, the terminal operates at a high utilization factor due to recent drop in spot LNG prices and good availability of cargoes.

Fig1.5.6b: Hazira Terminal: Capacity utilization (%)

iii) PLL – Kochi (5 MTPA)

The third LNG terminal of India has suffered due to pipeline connectivity issues. The connectivity to Bangalore is plagued by a dispute with Govt of Tamil Nadu, which has prohibited GAIL from laying the pipeline. Even though the Supreme Court has ruled in favour of GAIL, the completion is uncertain. The terminal has likely customers in MRPL, OMPL, MCF etc at Mangalore. The pipeline connectivity to Mangalore shall be completed in H1-2020, and the capacity utilizatuion is expected to reach 40-50%. The terminal has successfully re-negotiated its Long-term agreement with Gorgon at 13.9% down from 14.5% crude parity and pricing on DES instead of FOB basis. This will improve the cost-competitiveness of the terminal.

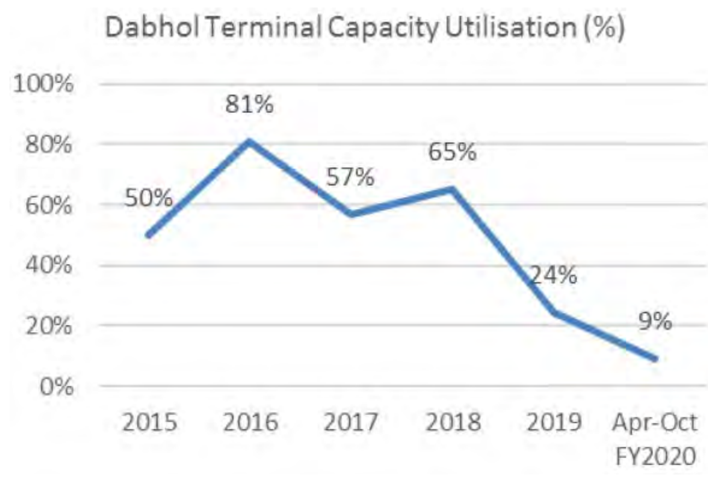
Fig1.5.6c: Kochi LNG Terminal: Capacity utilization (%)



iv) RGPPL Dabhol (GAIL) Existing– 1.9 MTPA, Nameplate – 5 MTPA

The fourth LNG terminal cannot operate during monsoons due to lack of breakwaters. However, breakwater is under construction and likely to be completed by 2020. GAIL has plans to invest Rs 3,000 Cr to double its capacity to 10 MTPA and utilize it for optimum utilization of the low-priced spot cargoes .

Fig1.5.6d: RGPPL Dabhol RLNG Terminal: Capacity utilization (%)



v) IOCL – Ennore (5 MTPA)

The fifth terminal of India is the first on the eastern coast near Chennai. The terminal has been commissioned in 2019 with a Capex of Rs 3,900 Cr. The terminal is to be connected with key industrial and commercial towns by the following pipelines

- A Trunk pipeline of 1,444 kms connecting Madurai, Trichy, Tuticorin in Tamil Nadu and Bangalore (via Hosur) in Karnataka being laid by IOCL.
- A Trunk pipeline connecting Ennore to Nellore being laid by Gas Transmission Ltd.

The key customers include Chennai Petroleum Corp, Madras Fertilizers, Tamil Nadu Petroproducts, Manali Petrochemicals, Power Plants in Karnataka and the CGD consumers in Tamil Nadu, Karnataka and Andhra Pradesh.

vi) Mundra LNG (5 MTPA)

The sixth operational terminal of the country has been promoted by GSPC, Adani, and other entities governed by Gujarat State Government. The terminal received its first cargo from Qtar in Jan 2020. The terminal is well connected with the pipeline network of GSPL. In the wake of low spare capacity at Dahej, it will cater to the demands of Chambal Fertilizers, Kota, the revived fertilizer plant at Gorakhpur, Refineries of IOCL and HMEL Petrochem and CGD demand for the Rajasthan, Haryana, Punjab, Uttar Pradesh.

B) Upcoming RLNG Terminals

1. Jaigarh LNG Terminal (4 MTPA FSRU)

India's first FSRU is promoted by H-Energy and is located at the Jaigarh port in Ratnagiri, Maharashtra. The contract has been signed with Total and the FSRU (Cape Anne) has been berthed. The commissioning is expected in Q2 of 2020. Jaigarh Port authorities shall provide all mlogistics support. There are plans for expanding the facility by installing an on-shore RLNG facility of ultimate capacity of 8 MTPA.

A 60-km tie-pipeline will connect the Jaigarh RLNG to the existing gas grid at Dabhol. The group has also received the authorization for the Jaigarh – Mangalore pipeline. The likely customers shall be the Refineries at Mumbai, Mangalore and other CGD development.

2. Chhara LNG Terminal (5 MTPA)

The terminal is promoted by HPCL & Shapoorji Pallonji, each holding 50% share in equity. This will be the fourth terminal in Gujarat. The EPC has been awarded to Toyo Engg and the completion is in 2022. It will meet the requirement of HPCL refineries in North and West, Fertilizer's expensions. However, the funding issues need to be resolved to ensure timely completion. The Greenfield facility has provision for expanding to 10 MTPA.

3. Dhamra LNG Terminal (5 MTPA)

The terminal is promoted by Adani Ports. Total has acquired a 50% stake in the project following their Agreement in 2018 with Adani. The expected Capex is about Rs 5200 Crores. IOCL has booked about 3 MTPA capacity on tolling basis for gas requirement at its refineries at Paradeep, Haldia and Barauni. GAIL has also contracted a capacity of 1.5 MTPA. Commercial operations are expected to commence in 2022. It can also cater to demand in Bangladesh and Myanmar, and the promoters have envisaged to carry out brownfield expansion to upto 10-12 MTPA.

The terminal is to be connected by the Trunk pipelines Jagdishpur-Haldia and Bokaro - Dhamra already under construction by GAIL. Its end-users are likely to include the Fertilizer Plants being revived at Barauni, Sindri and Gorakhpur.

4. Jafrabad LNG Terminal (5MTPA)

The terminal with a Capex of about Rs 6,000 Cr is being promoted by Swan Energy (63%) alongwith Gujarat Maritime Board (15%), GSPC (11%) and Mitsui OLK (11%). The terminal would be the fifth terminal in Gujarat. It would be laying a 24 inch pipeline of about 2 kms to connect with the GSPL pipeline network to access the hinterland CGD customers. It is also eyeing gas requirements of the IOCL refineries in Gujarat and HMEL Refinery, the second largest refinery in the country. The order for the FSRU has already been placed by the consortium on Hyundai Shipyards Korea.

The terminal shall have provision of an FSRU also. The Jafrabad Port Trust would carry out all logistics including dredging for ensuring berthing of Qmax along the FSRU.

H-Energy LNG Terminals proposed at Kakinada (Andhra Pradesh) & Kukrahati (West Bengal)H-Energy has also planned two FSRU based terminals on the East Coast; at Kakinada in AP and at Kukraheti (near Haldia) in West Bengal. The Kakinada terminal shall come up as a joint venture with Kakinada Ports, which shall provide the jetty.

The Kukraheti terminal near Haldia is targeted to serve consumers in East India and Bangladesh. The Terminal would have pipeline connectivity to Shrirampur near Satkhira border point on Indo-Bangladesh border and very close to Khulna, Bhola & Jeshore, the youngest and an upcoming gas consuming region in Bangladesh. The pipeline (Kanai Chhata – Shrirampur) has been authorized by PNGRB to H-Energy as per regulations in July 2019 and completion date is July 2022.

By 2025, a firm capacity of 66.5 MTPA (240 MMSCMD) from the LNG Terminals under construction would be in commercial operations. At 80% utilization, it would provide about 190-195 MMSCMD and at 86% utilization, it shall provide 200-205 MMSCMD.

By 2030, the FSRUs of H-Energy at Kukrahati and Kakinada may come on line. If demand is still there, H-Energy Jaigarh, Mundra and Dhamra terminal have capacity to scale up by 4 MMTPA each by brownfield expansions/ adding vaporisers and FSRUs in two years time. By 2030, an additional capacity of 20 MMTPA can come up. Till such time, the existing RLNG plants can perform at higher utilization levels, as witnessed at Dahej. Therfore, a feasible capacity of 66.5 can be on stream.

C) Challenges for new LNG Terminals

The regasification charges for the terminals and the pipeline tariffs will be key to utilization of the new terminals for which the customers have not booked firm capacities. Customers will prefer lower charges in view of the large volumes. If the aggregate demand is less than the aggregate capacity, then price competitivity would play a dominant role in capacity utilization. Following table brings out the existing Regasification charges of different terminals:

Table: Regasification charges at different terminals as in 2019-20

Terminal	Regasification Charges
Dhamra Terminal	Rs 60.18/mmbtu
Dhabhol Terminal	Rs 49.28/mmbtu
Ennore Terminal	Rs 57.38/mmbtu
Dahej Terminal	Rs 49.7/mmbtu
Kochi Terminal	Rs 104.5/mmbtu
Excelerate terminal (Bangladesh)	$1/mmbtu

(Industry Sources)

The capacity utilization for such terminals would also depend on the cost of sourcing of LNG cargoes. Lack of pipeline connectivity can constrain the evacuation of gas, as has been witnessed for the evacuation from the Kochi RLNG Terminal. Also, at least one or two anchor customers, from power plants, fertilizers, petrochem or refineries, will be crucial in lowering the operating costs and optimising margins. At present, Eastern and the Southern region lack the pipeline network. The fqct that most of the new entrants have decided to either lay their own tie-in / trunk pipelines or have tied up with GAIL and GSPL provides a great deal of certainty in evacuation. The PNGRB monitors the construction by organizing periodic review meetings.

1.5.3 Domestic gas supplies:

As per PPAC, domestic gas production and supplies peaked at 126 mmscmd in 2011-12 and have been declined to only 83 mmscmd in 2019-20 as brought out in Table below:

Table 1.5.3b: Year-wise gas production and supplies (in MMSCM)

	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
ONGC+OIL									
Gross Production	25946	26188	25910	24745	24015	25025	26311	27399	26414
Net Production	24993	25401	25242	23988	23242	24375	25743	26816	25726
Private / JVCs									
Gross Production	21609	14491	9497	8912	8235	6872	6338	5477	4770
Net Production	21460	14352	9332	8705	7887	6473	5988	5242	4531
TOTAL									
Gross Production	47555	40679	35407	33657	32249	31897	32649	32875	31184
Net Production1	46453	39753	34574	32693	31129	30848	31731	32058	30257

NOTE:

Net Production is gas available for consumption, which is derived by deducting from gross production, the quantity of gas flared/loss by producing companies.

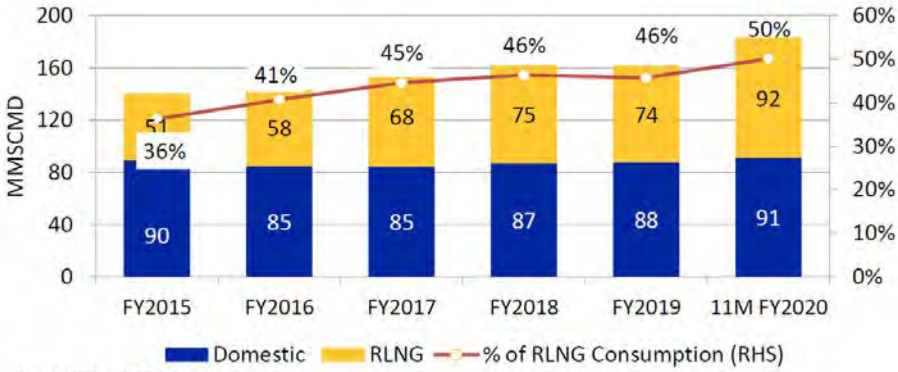
MMSCM: Million Standard Cubic Metre, Above includes Natural Gas and CBM

Source: PPAC, ONGC, OIL & DGH

1.5.4 RLNG Supplies

In 2004, the first LNG receiving terminal was commissioned at Dahej by Petronet LNG Ltd (PLL) followed by other terminals at Hazira (Shell), Kochi (PLL), Dabhol (RGPPL) and Ennore (IOCL). The share of RLNG has gradually picked up in the gas economy of India. It was expected that in 2019-20, RLNG shall constitute about 53% share of gas consumption in the country. The year-wise share of natural gas and RLNG is as follows:

Fig 1.5.7:Yearwise Share of Domestic gas and RLNG

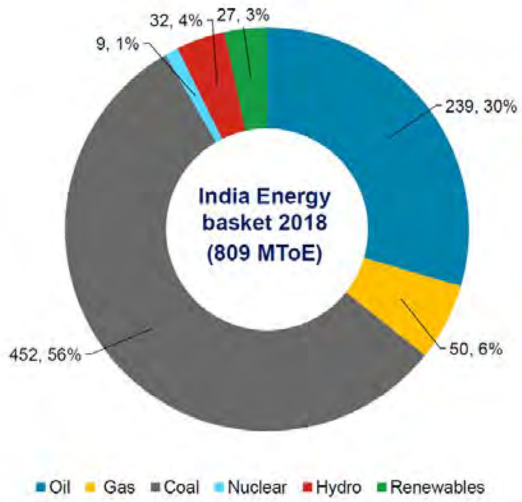


Source: PPAC, ICRA research

Share of gas in India's Primary Energy requirement.

As in 2019-20, share of Gas was about 6.2% in India's Primary Energy consumption, with coal and oil together comprising about 86% share as enumerated below:

Fig: 1.5.8: Share of gas in India's Energy Basket in 2018-19

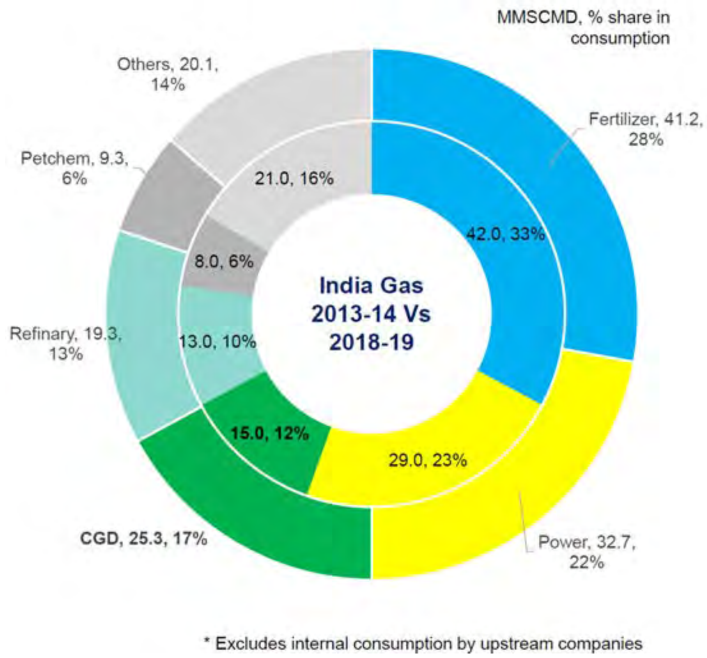


From 2015 onwards, the domestic gas production stagnated, and the growth in demand for gas was met from the RLNG plants. However, in spite of growth of gas consumption, the share of gas in India's energy basket fell from 6.6% in 2015 to a mere 6.2 % in 2019-20.

1.5.5 Sector-wise gas consumption

Fertilizers and Power sector were the main consumers of gas and till 2011 they comprised two-thirds of the supplies. After the decline from KG D-6 in 2011, the consumers turned to RLNG. However, the cost of generation was high on RLNG and gas based capacity installed with likely sourcing from the KG D6 supplies could not match the generation cost of coal-based plants and lost out on finalizing their PPA. As such the share of power sector has gradually come down from 33% in 2013-14 to about 23% in 2018-19 as in the figure below:

Fig 1.5.9: Sector wise consumption in 2018-19 compared with 2013-14



(Source: GAIL)

1.6 Gas Supply and Demand

1.6.1 Gas supply projections:

A) Domestic gas

The Government has resolved to increase the share of gas to about 15% by 2030. Several initiatives have been launched to boost domestic production of Natural and Unconventional gases. While the production from existing fields are declining, about 50 - 55 MMSCMD is likey to be produced by 2028 from the KG Basin by ONGC & RIL. Expected domestic gas production is expected to go up to about 50-55 bcm (146 mmscmd) by 2028 and 60 bcm by 2030.

Table 1.6.1 : RLNG Supply Forecast : Existing and 'Firm' Regasification Terminals

Company / Location	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25
PLL, Dahej	15	15	15	16.2	17.5	17.5	18.1	20	20
PLL, Kochi	0.4	0.5	0.5	0.5	2	2.5	2.5	2.5	2.5
Shell, Hazira	5	5	5	5	5	10	10	10	10
RGPPL, Dabhol	3	3	3	3	3	5	5	5	5
GSPC-Adani, Mundra				0.5	5	5	5	5	5
IOC, Ennore				0.7	5	5	5	5	5
H-Energy-Jaigarh Port, Ratnagiri					4	4	4	4	4
Adani-IOCL-GAIL - Dhamra						2.5	5	5	5
Swan Energy, Jafrabad						5	5	5	5
HPCL-Shapoorji Pallonji, Chhara							2.5	5	5
Total LNG Capacity (in MMTPA)	**23.4**	**23.5**	**23.5**	**25.9**	**41.5**	**56.5**	**62.1**	**66.5**	**66.5**

(Source: ICRA)

B) RLNG Supply capacity forecast

Based on the current progress of the RLNG plants and the associated pipeline infrastructure, it is expected that a capacity of 41 MTPA (about 150 MMSCMD) is expected to be available in FY 21. See the figure below:

Table 1.6.1: RLNG Supply Forecast

Company Name, Location (MMTPA)	FY 17	FY 18	FY 19	FY 20	FY 21	FY 22	FY 23	FY 24	FY 25
PLL, Dahej	15	15	15	16.2	17.5	17.5	18.1	20.0	20.0
PLL Kochi – Effective	0.4	0.5	0.5	0.5	2	2.5	2.5	2.5	2.5
Shell, Hazira	5	5	5	5	5	10	10	10	10
RGPPL, Dabhol	3	3	3	3	3	5	5	5	5
GSPC-Adani, Mundra				0.5	5	5	5	5	5
IOC, Ennore				0.7	5	5	5	5	5
H-Energy-Jaigarh port, Ratnagiri					4	4	4	4	4
Adani Enterprises, IOC and GAIL - Dhamra						2.5	5	5	5
Swan Energy, Jafrabad						5	5	5	5
HPCL, Shapoorji Pallonji - Chhara							2.5	5	5
Total LNG Capacity (MMTPA)	**23.4**	**23.5**	**23.5**	**25.9**	**41.5**	**56.5**	**62.1**	**66.5**	**66.5**

(Industry Sources, ICRA)

1.6.2 Gas Supply Scenarios

The supplies from domestic gas fields have a fair degree of uncertainties. Similarly, the new RLNG terminals, eight of which are under construction or the Brownfield expansion, can face delays. The capacity utilization also depends on various factors like supplies of LNG and their off-take on a consistent basis. Accordingly, following two gas supply scenarios have been drawn:

Scenario 1: Reference Scenario:

This scenario assumes domestic gas supplies as per the planned production profile, low to moderate crude prices, and, surplus production of LNG. The low crude prices will ensure lower prices of term LNG which are benchmarked to Crude. The surplus production from LNG plants can be due to lower demand than expected, and would lead to softer prices for the Spot LNG cargoes. The firm capacities of LNG receiving terminals under construction have been taken till 2025 and subsequently brownfield/ greenfield capacity addition of 2 mtpa are assumed.

Following assumptions have been made to project the gas flows:

- Delivered LNG prices less than 5-6$/mmbtu
- Commissioning of RLNG capacities as scheduled
- High capacity utilizations, viz 85% till 2030 and beyond is considered at 80%.
- The actual domestic production as projected by ONGC, RIL, OIL & others.

The gas supply forecast emerges as follows:

Table 1.6.2 a Gas Supply Scenario 1: Surplus RLNG + Optimistic Domestic Gas

Gas Supply Scenario 1: Reference Scenario						
Source		2019	2020	2025	2030	2040
RLNG	In MTPA	23.5	25.9	66.5	76.5	96.5
	Utilization in %	87	85	85	80	80
	Gas in mmscmd	74	79	203	220	278
Domestic Gas		90	87	138	154	155
Total Gas		**164**	**166**	**341**	**374**	**433**

Scenario 2: Conservative scenario:

This scenario assumes Crude prices upwards of 50$/bbl upto 60$/bbl and tight LNG markts. This will result in higher prices of Term & Spot LNG with delivered prices LNG prices above 6.5 - 7$/mmbt, leading to lower utilization of LNG Terminals. The capacity addition also comes down by a quarter after

2025. This scenario also assumes Domestic Gas production at 90% of the planned production profile.

This gas supplies in this scenario is arrived upon taking into account the following:

- Timely commissioning of RLNG capacities
- Utilizations about 5% in less in 2025 and beyond due to LNG prices upwards of 7 $/mmbtu
- Lower capacity addition in LNG receiving terminals, as growth declines by a quarter
- The actual domestic production at 90% of planned in 2025 and 2030

The supply scenario emerges as under:

Table 1.6.2 b Gas Supply Scenario 2: Conservative Scenario (Crude 50 – 60 $/bbl, RLNG upwards of 6 $/mmbtu and Domestic production@ 90%)

Gas Supply cenario 2: Conservative Scenario						
Source		2019	2020	2025	2030	2040
RLNG	In MTPA	23.5	25.9	66.5	74	89
	Utilization	87	85	80	75	75
	Gas in mmscmd	74	79	192	200	240
Domestic Gas		90	87	124.2	138.6	139.5
Total Gas		**164**	**166**	**316**	**338**	**380**

1.6.3: Gas demand Analysis: Key economic drivers

Macro-economic parameters: Pace of urbanization, low per capita consumption etc

As per BP Statistical Review 2019, Indian economy is expected to treble by 2040,a key driver in the growth of India's Primary energy consumption. The country's share in Primary Energy is expected to grow from existing 6% to 11%. The country is expected to contribute to 25% to the global growth of Primary Energy consumption, making India the largest source of energy demand growth. At present, only 35% of the population is in Urban areas, way behind the average Urbanization of 50% in Asia and 55% across the globe. Increase in Urbanization is expected to increase the energy demand for electricity and transportation. In spite of a growth in Renewables (from 20 Mtoe to 300 Mtoe in 2040), India's dependence on coal in electricity will continue to dominate. The gas consumption is likely to grow 240% (185 bcm or about 510 mmscmd) till 2040.

Commitment to clean energy and Government's policies:

Reduction of its GHG intensity of its GDP by 33 – 35% below the 2005 levels by 2030 is one of the four key commitments in the NDCs for climate change goals pledged by India in the Paris Agreement of the COP-21 (2015). India's contribution in the growth of CO2 emissions last year was only 15%, behind China (34%) and US (20%).

In 2017, the Draft National Energy Policy prepared by the NITI Aayog (formerly Planning Commission, the key Policy think-tank body of the Governmental of India with Prime Minister as it's Chairperson) projected a share of about 8 to 9% for Gas in the primary energy mix in 2040. Considering that the fossil fuels shall still contribute about 78% in the primary mix in 2040, it means that in absolute terms, the contribution of gas could be quite significant. Subsequently, the government has however set a higher target for gas. The Ministry of Petroleum & Natural Gas has projected a target of 15% for gas in the coming years as appearing in its Annual Report 2018-19. Even the NITI Aayog targets in absolute terms could see an increase by 2.5 times in gas consumption by 2040.

As per an assessment compiled by GAIL, the policies in hydrocarbons could see substantial investments in the short to mid-term. It has projected that the investments could be about Rs 773,000 Crores (100 Billion USD) till 2026 with the following break-up:

1. E&P: Rs 402,000 Cr
2. Gas Grid: Rs 92,000 Cr
3. LNG Terminal: Rs 16,000
4. CGD: Rs 90,000 Cr
5. SATAT: Rs 175,000 Cr

Accessibility to gas

One of the key outcomes of the planning and investments in the CGD sector together with that for gas pipeline network (under the 'One nation- One grid' initiative) is the enhancement in accessibility to gas for the larger population. In the next 3-4 years, there would be adequate transmission network to support the gas availability for the entire refineries, petrochemicals, and CGD sectors.

Tighter Environmental Norms

The MoEF has come out with tight emission norms for NOx, SO2 etc, and this is likely to dampen the generation from coal-based power.

HFO is a highly polluting fuel and its use has been banned in many parts of the country. It has been phased out from all power plants, where it was being used as a secondary fuel. It is anticipated that once pipeline connectivity iis available, HFO shall be totally phased out.

Emerging opportunities for LNG

1. Distribution channels: There have been considerable developments in transportation of LNG by Rail Containers and LNG trucks. LNG barges for fuelling of coastal gas-based stations also have potential.
2. LNG for City Buses and long-haul trucks: The LNG storage pressure is very low and chances of leakage are less than CNG, thereby improving the safety concerns. The storage is also about 3 times of CNG and in one tank-ful, the buses can ply upto 600-700 kms. LNG long-haul trucks have been very successful and popular in China and the price arbitrage over HSD will trigger migration once adequate re-fuelling facilities are developed. Petronet plans to install 1350 LNG dispensing stations spread over 35,000 kms out of 1,31,000 kms of National Highways. Petronet has also tied up with Tata Motors, and have recently commissioned the first LNG-fuelled 'Starbus' for intra-city commuting recently in March.
3. Trials for use of LNG for Railway Locomotives: After successful trials of CNG in its Diesel-electric Mutiple Units (DEMU /DMU),the Indian Railways Organization for Alternate Fuels (IROAF) have placed orders for 30 CNG-fuelled DEMUs. It is gathered that awaiting development of safety standards for LNG-fuelled Locos.
4. Bunker fuels for ships & barges: As per SEA-LNG, some 96 ports across the globe have already LNG bunkering infrastructure and 55 more ports are in the process of installing such facilities.
5. Virtual Gas supplies for regions devoid of sourcing gas by pipelines, are foreseeable opportunities, backed by Soft pricing of LNG.

1.6.4 Sector-wise analysis of demand

A) Power Sector

The power sector was one of the first anchor customers of gas and helped in laying of the first trunk gas pipeline, the HVJ (Hazira-Vijaipur-Jagdishpur) in the country. Over the years, the country has an installed capacity of about 25 GWs of Gas-based Combined Cycle Gas Turbines (CCGTs). At base-load operations, with capacity utilization of 85%, the potential for consumption is nearly 110 mmscmd or about 30 MTPA of LNG. This potential of consumption has been examined to assess the emerging demand in the sector.

i) Existing Gas based capacity

Out of the total capacity of about 25 GWs, about 4 GW is in the North-East, which are not connected to the National Pipeline Grid and consume locally produced gas The remaining 21 GW of gas based capacity is connected with the Pipeline Grid. About 7 GWs capacity have domestic gas allocations (APM, PMT, & Non-APM), and they operate at about 20-22% capacity utilization. The remaining 14 GWs, which had been planned based on future gas supplies from KG D-6 basin of RIL, are stranded as the production has declined considerably.

ii) Impact of Gas Prices on Tariffs and generation

The tariffs are determined as per the Power Purchase Agreement (PPA) between the Generating Stations and the Discoms. For most of the plants, Tariffs are in two parts, the Capacity Charges and the Energy charges. For the plants which have adopted the CERC's 'Cost Plus' tariffs, Capacity charges (Fixed costs like ROE, Depreciation, Fixed O&M costs, Debt servicing and Interest on working capital) are paid based on the 'availability' and Energy charges (Variable costs or the fuel costs as per the landed price of fuel and the net heat rate) are paid for the energy generated against the schedules. For compiling the Merit Order for scheduling purpose, the Energy Charges or the Variable costs are considered. Tariffs for various sources of generation are in the Table below:

Generation Source	Tariffs
	(in Rs /Unit)
Coal-based (Variable Charge)	
Pithead (with 100% linkage with notified domestic coal)	1.5 to 2.0
Rail-fed (with 100% linkage with notified domestic coal)	3.0 to 4.0
Rail fed (80% linkage coal with 20% imported coal)	3.5 to 4.25
100% Imported coal based (Landed price 70 $/t for 5000 GAR)	3.0 to 3.5
Gas-based (Variable Charge)	
Domestic APM Gas based (Gas price 2.39 $/mmbtu)	2.1 to 2.6
RLNG-based (Delivered Gas price at 8 $/mmbtu)	5.0 to 5.5
Competitive bid based (Levelised Tariffs)	
Wind plants (2018 & 2019)	2.6 to 2.8
Solar plants (2018-19)	2.6 to 2.7
Medium Term PPA (PTC) -2018	4.5
Medium Term PPA (PTC) -2020	3.4
PPA - Power purchase Agreement, PTC - Power Trading Corporation	

Scheduling Procedures

The scheduling and generation of Power plants are regulated by the Grid Code and Operating Procedures as per Central or State Electricity Regulatory Commissions (CERC/SERC). The generators declare their fuel-wise capacity (availability) for 96 time- blocks of 15 minutes each for the 24 hours of the day. The thermal plants have to declare the fuel source and their landed costs upfront. The Discoms / Off-takers provide their demand for the 96 time blocks.

In the present scenario, the availability exceeds the demand. Consequently, the merit order of despatch from respective generation sources is utilized for fulfilling the demand. The generators which are higher on Merit order (i.e. with lower energy costs) are scheduled in preference to the generators which are low in the Merit order (i.e. with higher energy cost) lose out once the energy demand is met.

As illustrated in the table above, the energy cost on domestic gas based generation fits in the merit order and is scheduled and off-taken by the Discoms. It may also be observed that energy cost on RLNG (at 8 $/mmbtu) is even higher than other sources. As energy cost on RLNG-based generation is low in merit order it loses out in scheduling by the off-takers / Discoms. Due to shortage of domestic APM-priced gas, even the Gas-based capacities of 7 GWs (on domestic APM priced gas) are compelled to source RLNG. However, they do not receive generation schedule on RLNG and therefore operate at around 20-22% PLF, commensurate with the domestic gas availability.

The remaining 14 GWs capacity which was installed on the assurance of supplies from KG D-6 basin, could not be effectively utilized as these plants faced severe fuel supply issues. The production from the KG D-6 basin increased to an average 55.35 mmscmd in 2010-11, and then began declining to just 25.74 mmscmd in 2012-13 as illustrated in Table below:

Table 1.6.3: Availability of KG-D6 gas to all sectors

Year	2009-10	2010-11	2011-13	2013-14
Supply in MMSCMD	39.67	55.35	42.33	25.74

(Source: CEA: NEP 2017)

In 2013-14 and thereafter, the production from KG D6 gas fields further declined and the Gas-based capacity of 14 GWs, which was installed on the assurance of supplies from KG D-6 basin, was left without any reliable alternate source of competitively priced domestic gas. Many of these plants did not have any other supply source as reverse flow in the East-West Pipeline was not possible. Even those plants which had pipeline connectivity to receive RLNG, could not generate energy costs were low in merit order. Further, the priority in gas allocation also shifted in favour of CGD Sector. This affected the capacity utilization of Gas-based plants. The gas availability for the power sector touching a high of 59.31 mmscmd in 2010-11, it came down to just 29.59 mmscmd in 2016-17 and to about 21 mmscmd in 2018-19 in spite of addition in capacity as illustrated in the table below:

Table 1.6.4: Year-wise gas based Capacity and Gas supplies

	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017
Gas Based Capacity	13408	13599	15769	16639	16926	18362	20385	21666	23076	24037
Average Gas Supplies	38	37	55	59	56	40	27	25	28	30

NOTE:
Above includes Domestic Natural Gas (APM, PMT & Non-APM at Government regulated prices) and RLNG
MMSCM: Million Standard Cubic Metre
Gas based Capacity in in MW at the end of Financial Year.

Source: CEA

Many of the KG-D6 gas-based plants do not have PPAs with the 'Cost plus' tariff structure (CERC – Two part model) and are unable to recover their 'Capacity' or 'Fixed' costs. Consequently, for want of competitively priced domestic gas, these plants totalling about 14 GWs capacity are practically 'stranded' with outstanding debts and accrued interest burden and many of these plants are facing liquidation and are in the National Company Law Tribunal.

iii) Generation Planning & Utilization of Gas-based capacity:

Assessment of the demand for gas by the power sector calls for analysing the demand forecast for the peak demand and electrical energy, the key environmental and technical issues central to selection of the generation-mix. Forecasting or projecting electricity demand for peak and energy requirements in India is an integral part of the planning by Central Electricity Authority (CEA), the statutory body which functions as per the Part IX of the Indian Electricity Act 2003. CEA supports the Ministry of Power in forming policies, technical standards, regulations, as well as to disseminate power sector information to all stakeholders of the Power sector in India. The CEA carries out key studies as regards the long term planning of Electricity sector. In the past three years it has brought out reports on the 19th Electricity Power Survey (2016-17 to 2026-27), National Electricity Plan (2017), Flexible Operation of Thermal Plants for Integration of Renewable Energy (2018) and Draft Report on Optimal Generation mix for 2029-30 (2019) and Long-term Electricity Demand Forecasting (2019). Together, these reports present a fair scenario of the electricity sector till 2036-37. The existing gas-based capacity has a potential of

70-75 mmscmd at 60% capacity utilization and so have been referred for analysing the generation mix from different sources including gas.

a) 19th EPS (Electricity Power Survey)

CEA carries out demand forecasting every five years. The latest one in the series is the 19th EPS issued in 2017, which utilizes the bottoms up approach to determine the demand for power and energy, using the final energy needs of all categories of consuming sectors. As per EPS 2019, the expected peak demand in 2021-22 is about 226 GW and in 2026-27 is 299 GWs, with CAGR of 6.88% and 5.77% respectively. The projected energy consumption in 2021-22 is about 1300 BUs and in 2026-27 is 1743 BUs with CAGR of 7.15% and 6.03% respectively. The T&D losses are expected to be brought down from 20.65% in 2016-17 to 16.96% in 2021-22 and further down to 14.87% in 2026-27. The energy requirement is expected to be 1566 Bus in 20121-22 and 2047 Bus in 2026-27 with CAGR of 6.18% and 5.51% respectively. The details are in table below:

Table 1.6.5: Peak Demand and Electrical Energy requirement in 2026-27 as per 19th EPS

	Year			CAGR (%)	
	2016-17	2021-22	2026-27	2016-17 to 2021-22	2021-22 to 2026-27
Electrical energy consumption (MU)	920,837	1,300,486	1743,086	7.15	6.03
T&D losses (MU)	239,592	265,537	304,348		
T&D losses (%)	20.65	16.96	14.87		
Electrical energy requirement (MU)	1160,429	1566,023	2047,434	6.18	5.51
Peak Electricity Demand (MW)	161,834	225,751	298,774	6.88	5.77
Derived Load factor (%)	81.85	79.19	78.23		

(Source CEA)

b) NEP (National Electricity Plan) - 2018

Based on the Peak Demand and Electrical Energy requirement in the 19th EPS, CEA has carried out the Generation planning to ensure that the emerging demand is fully met with commensurate capacity additions and its utilization in a sustainable manner. It is also required for the optimum utilization of all resources and fuels. It also plans integration of generation from Renewable Energy sources in the energy mix.

- Amount and sources of Emissions

The objective function of the programming is minimizing the above.

The optimization studies in NEP have planned generation capacity for integrating the Government of India target of 175 GWs of renewable capacity by 2021-22, including meeting the peaking and ramping requirement of the system. In the NEP, it is assumed that the Gas Power plants would operate at minimum load during the off-peak and ramp up during the peaking requirement of the grid. PLF of Gas-based capacity during 2021-22 is likely to be around 37%, compared to the then prevailing 22%. The corresponding gas requirement worked out as 45.27 MMSCMD, which could be brought down in the event of utilizing full peaking potential of Hydro stations and possible two-shift operations of some coal-based thermal power plants.

The NEP also recommended ways and means to revive and improve the capacity utilization from the gas-based projects by schemes like the Scheme for Utilization of Bas-based Generation Capacity) introduced by the Govt of India in 2017. This scheme envisaged supply of imported LNG to the stranded power plants as well as plants receiving domestic gas to improve their utilization. The scheme provided several sacrifices or 'haircuts' collectively by the stakeholders including Government, suppliers, transporters, transmission companies as well as the generator.

Key Haircuts/ Sacrifices by Stakeholders under the GOI imported LNG scheme for gas-based stations

- Waiver of custom duty, VAT, CST, Octroi and Entry Tax by the Central/State Governments and waiver of Service Tax on Regasification and Transportation charges.
- Reduction in Pipeline Tariffs by 50%, Marketing Margin by 75%, by GAIL & other
- Power developers to forego Return on Equity and Fixed Costs to be capped
- Provision of Comingling and swapping of gas
- Exemption from transmission charges and losses
- Financial support from Power System Development Fund (PSDF)

For procuring this gas, the gas plant developer would have to bid for the quantity of gas and the generation from it and the lowest quote would be awarded the gas. Although the scheme was successful, however it was withdrawn after two rounds. As substantial gas-based capacity remains stranded, the lenders and the promoters have approached the governments at State/Centre to find some similar policy intervention for facilitating RLNG's consumption and utilize the capacity to enable at least debt servicing and recovery of operation costs. The NEP recommended that this scheme be continued on a more firm basis.

c) Draft Report on Optimal Mix (Feb 2019):

CEA, in this study has re-assessed the optimum generation mix in 2029-30. The data of demand projections and generation planning as per 19th EPS the NEP-2018 have been utilized. The 19th EPS contained year-wise projections upto 2026-27. So the demand projections for 2029-30 have been extrapolated by CEA using a CAGR of 4.4% for Peak Demand and 4.33% for Energy demand beyond 2026-27, which is in Table 1.6.6 as follows:

Table 1.6.6: Peak and Electrical Energy Demand considered (Ref CEA Draft Report on Optimal Gen Mix)

Year	Electrical Energy Requirement (BU) Ex Bus	Peak Electricity Demand (GW)
2021-22	1566	225.751
2026-27	2047	298.774
2029-30	2325	339.973

In addition, it extensively utilized generation forecasting software tool called ODERNA. The software projects the Short-term planning in terms of the hourly demand and source-wise generation as also the Long-Term planning for Annual Fuel-wise requirement and the Total System costs.

As per the projections in the Report, Installed Capacity in 2029-30 would be about 832 GWs, with about 300 GW of Solar. The rest comprises mainly of 291 GWs of thermal (net post-retirement of old coal-based thermal plants), 140 GWs of Wind, 73 GWs of Hydro (including small hydros and imports), about 17 GWs of Nuclear and about 10 GWs of Biomass as in the table below:

Table 1.6.7:Capacity mix in 2029-30 to meet Peak and Energy Demand as per 19th EPS

Fuel Type	Capacity (MW) in 2029-30	Percentage Mix (%)
Hydro *	73,445	8.8
Coal + Lignite	2,66,827	32.1
Gas	24,350	2.9
Nuclear	16,880	2.0
Solar	3,00,000	36.1
Wind	1,40,000	16.8
Biomass	10,000	1.2
Total	8,31,502	
Battery Energy Storage	34,000MW/136,000MWh	

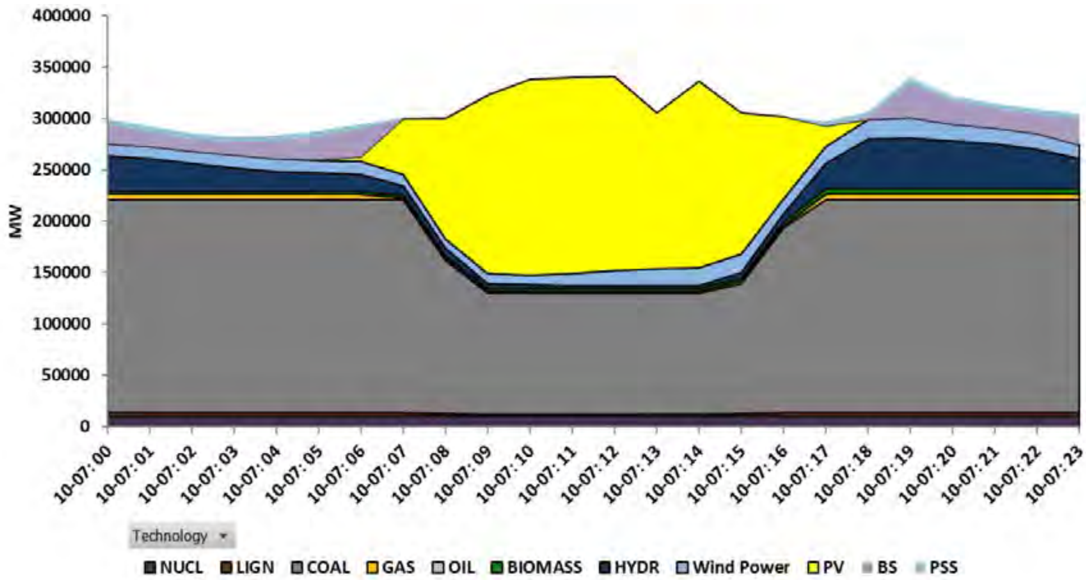
* including small hydro of 5000 MW and hydro imports of 4356 MW

(Ref CEA Draft Report on Optimal Gen Mix)

As per the projections, about 2400 Bus of electrical energy would be required in 2029-30, and about 2% of energy generation is from the Gas-based power plants. This means that about 48 BUs would be generated by Gas-based plants and the required gas would be about 11 bcma or about 30 MMSCMD. This is a significant down-scaled consumption as compared to about 45 mmscmd in the NEP- 2018.

The report points out that the model indicates that a significant capacity of nearly 34 GWs (136 GWh) of Battery Storage system is to be added from 2025 till 2029-30. It would act like energy storage during the renewable curtailment period, and released to meet the evening peak demand. As per the daily hourly generation charts, Battery Storage is contributing significant energy, much more than Gas-based plants. The typical generation for the peak energy day of 2029-30 is as below:

Fig 1.6.2: The source-wise hourly generation curve for the Peak Demand & Energy day in 2029-30



(Source CEA)

iv) Battery-based energy storage v/s Gas based generation

With increase in capacity additions of Wind and Solar, Battery-based energy storage systems are increasingly gaining popularity across the globe. In the Indian context, we make an attempt to compare new capacity additions in Battery based storage vis-a-vis Gas-based capacity on three counts, (i) Capital Expenditure (Capex), (ii) Cost of supplies/ levelised tariffs and (iii) Capability to meet ramp-up rates.

a) Capex required

As the CEA's draft report on Optimal Generation Mix 2029-30, the prevailing capital cost of the battery storage systems is in the range of Rs 7 Cr (Rs 70 Mn) per MW/4 MWHr after taking into account additional capacity to provide the rated energy upto the depth of discharge. By 2029-30, the capital cost is expected to come down to Rs 4.3 Cr (Rs 43 Mn). By 2029-30, an investment of about Rs 192,000 Cr (Rs 192 Bn / 2.6 Bn USD) is envisaged.

The 34 GW of Battery System would provide about 136 GWHrs of Energy, whereas, the existing Gas based capacity of about 26 GW operating at 75% PLF has potential for generating 330 – 350 GWHrs over and above the existing PLF of 21%.

b) Tariffs for Battery Storage & Gas-based

Levelised Tariffs for Battery Storage: The levelised tariffs for Battery systems have been developed in three scenarios:

Scenario A: The tariff norms are as per CERC, and the same has also been assumed by CEA for simulation as also in the NEP 2018. Debt to Equity is 70: 30, Return on Equity is 15.5% post tax, Debt at 11.5%, O&M cost @ 2% as in the CEA's Draft Report on Optimal Mix, Working Capital and interest as per prevailing CERC norms and Discounting at 9%.

Scenario B: This could be the emerging scenario in times when debt rates and returns are lower. ROE is taken as 14% (post tax), Debt at 10%, Reduced Interest on Working Capital, Discounting factor as 8%.

Scenario C: This is a most aggressive scenarios assuming that cheap debt at 7.5% would be available and ROE is limited to a mere 12% (post tax). Interst on Working Capital is taken as 8.5% (300 BPs above the projected SBI MLR @ 5.5%)

Ideally, the energy supplied to the Battery system has to be the grid power. However, assuming that cheap off-peak power could be available, the energy charge rate has been taken as Rs 2.0 per kwhr.

The assumptions are tabulated below in table 1.6.9(a).

Table1.6.9 (a) Assumptions for Levelised Tariffs for Battery Systems

Scenario	Scenario A	Scenario B	Scenario C
ROE @ (Post-Tax)	15.5 %(Existing CERC)	14.00%	12%
Indian Debt (100% Non Escalable)	11.5% (Existing CERC)	10%	7.50%
O&M Cost (As per CEA Report on Optimal Mix for 2029-30)	2% of Capex		
Debt: Equity (CERC Norms of Max 70: 30)	70%: 30%		
Cost of Energy Supply (Escalable @ 3% p.a.)	Off- Peak power @ Rs 2/- per kwhr		
Working Capital: As per CERC Norms for Tariffs of TPPs	Fuel Cost for 1 month, 45 days Receivables, Maint Spares @ 20% of O&M cost, O&M Expenses as 1 month of O&M cost		
Interest on working Capital (6-Mnthly SBIMLR + 3%)	9.7% (Existing CERC)	9%	8.50%
Discounting Rate	9%	8%	7%

The life of the battery system is generally for 10,000 cycles or about 10 years. However, we have also assumed an extended life of upto 15 years. The levelized tariffs at Capex Rs 70 Mn/MW work out as Rs

13.2 per kwhr for a 10 year life in the existing Scenario A. Even for the aggressive investment Scenario C, the tariffs work out Rs 11.7 per kwhr. The tariffs in different scenarios, Life of Plant and Capex norms are tabulated below.

Table 1.6.9 (b) Battery System Levlized Tariffs (Rs / Kwhr)

Scenario	A		B		C	
Life (in years)	10	15	10	15	10	15
Capex @Rs 70 Million/MW	13.2	12	12.5	11.3	11.7	10.5
Capex @Rs 43 Million/MW	9.9	9.3	9	8.3	8.5	7.9
Depth of Discharge - 4 hours						

Levelised Tariffs for LNG Based plants (IPPs): A substantial capacity of stressed Gas-based plants have F- Class or Advance F- Class Gas Turbines which have heat rates of 1750-1800 Kcals/kwhr upto 85%PLF. An attempt has been made to estimate the levelised cost of these gas-based capacity as per CERC / CEA Norms as in NEP.

Similar to determining the levelized tariffs of the Battery System as above, three scenarios have been considered, Scenarios A, B & C.

The capital cost of these plants have been assumed as Rs 35 Million/MW, Debt to Equity as 70: 30, 100% debt from Indian Lenders, Depreciation as per NEP / CERC (5.28% for the first 12 years and then distributed over the rest life of plant with residual value of 10%). Life of the plant has been taken as per CERC Norm of 25 years.

The cost of Term LNG has been taken at 10% DES with Crude at 50 $/mmbtu i.e., at 5 $/mmbtu DES, at a Gujarat based terminal and has a 15% Gujarat Gas Tax on Gas. The Duties & taxes, pipeline tariffs, Marketing margins, GST, VAT etc have been taken for destination plant Dadri. In view of part load operations/ start stops, the heat rate has been taken at around 1950 Kcals/kwhr, or about 12-15% higher than rated for an F-Class Gas Turbine.

Table 1.6.9 (c) Assumptions for Levelised Tariffs for Gas Based IPP

Scenario	Scenario A	Scenario B	Scenario C
ROE @ (Post-Tax)	15.5 %(Existing CERC)	14.00%	12%
Indian Debt (100% Non Escalable)	11.5% (Existing CERC)	10%	7.50%
O&M Cost (CERC Norms for F Class Gas Turbines)	2.727 Mn Rs /Year /MW		
Capital Cost	Rs 35 Mn / MW		
Debt: Equity (CERC Norms of Max 70: 30)	70%: 30%		
Variable Cost of Generation (Escalable @ 3.5% p.a.)	Rs 4.5/kwhr (F Class GT of HR 1950 Kcals/Kwhr) LNG price DES @ 10% of Crude at 50 $/bbl, Regas cost, Tpt Tariffs, Taxes, duties, Mktg margin as applicable for Dadri CCGT		
Working Capital: CERC Norms for Tariffs of TPPs	Fuel Cost for 1 month, 45 days Receivables, Maint Spares @ 20% of O&M cost, O&M Expenses as 1 month of O&M cost		
Interest on working Capital (6-Mnthly SBIMLR + 3%)	9.7% (Existing CERC)	9%	8.50%
Discounting Rate	9%	8%	7%

The levelized tariffs have been worked out for 25%, 33% and 50% of Capacity Utilization. Gas turbines have a high technical minimum load as compared to coal plants and efficiency deteriorates at partial loading. However, the operation philosophy would be such that number of gas turbines in operation would ensure that even if the overall utilization of the gas capacity is 25% to 50%, they are able to operate at around 15% higher heat rates. The levelised tariffs in the present Scenario A works out to Rs 10.6/kwhr even at 25% capacity utilization. In a more aggressive or a negotiated scenario for lower interest rate on Debt, it can be reduced to Rs 10.2 / Kwhr as in Scenario C. The Levelised tariffs for the Scenario A, B, & C for Capacity Utilization as 25%, 33% and 50% are as in Table below:

Table 1.6.9d: Gas based plants Levlized Tariffs (in Rs/ Kwhr)

Scenario	A	B	C
25% Utilization	10.6	10.4	10.2
33% Utilization	10.4	9.4	9.2
50% Utilization	10.2	9.2	8.3

Many of these plants are stressed and with NCLT, the capital cost can be brought down by negotiations by new investors. This can help in reduction of capacity charges in tariffs.

Tariffs of NTPC's Gas Based capacity: The NTPC plants have depreciated to a large extent and therefore the fixed cost is quite low. These plants still have about 4-7 years of balance life. While RGPPL, a JV company, has F-Class Gas Turbines with Heat Rate of 1750-1800 Kcals/kwhr , the remaining plants have D & E-Class Gas Turbines with heat rates from 2000 – 2125 KCals/kwhr.

A levelised cost has been worked out for a 7-year life of these plants of about 4000 MW capacity. The Term RLNG gas supply contract is likely to end in a year or so, and a fresh Term LNG Supply contract can be entered in at 10 – 11% slope with Crude prices. These plants also have Domestic gas allocations. Except Anta, all plants have module configuration of 2GT + 1 ST and therefore operation of even 30 % of the total capacity on RLNG (in addition to domestic gas) along with bundling and swapping gas between plants can be carried out with Heat Rates not exceeding 2200 kcals/kwhr. Further, an additional 10% has been considered for start / stops as these are older machines. The tariffs work out to about Rs 6.3 to Rs 8.8/kwhr for Crude at 40 $/bbl to 60 $/bbl at 40% PLF and between Rs 6.7 to 9.2/ kwh as in the table below:

Table 1.6.10: Tariffs for NTPC's gas-based plantsfor NTPC Plants

Levelised Tariffs for NTPC Plants						
Crude in $/bbl	40		50		60	
LNG price DES	10%	11%	10%	11%	10%	11%
Variable Cost	5.2	5.5	6.1	6.6	7.0	7.6
Fixed Cost @ 30% Normative Availability	1.6	1.6	1.6	1.6	1.6	1.6
Fixed Cost @ 40% Normative Availability	1.2	1.2	1.2	1.2	1.2	1.2
Tariff @ 30% PLF	**6.7**	**7.1**	**7.7**	**8.1**	**8.6**	**9.2**
Tariff @ 40% PLF	**6.3**	**6.7**	**7.3**	**7.7**	**8.2**	**8.8**

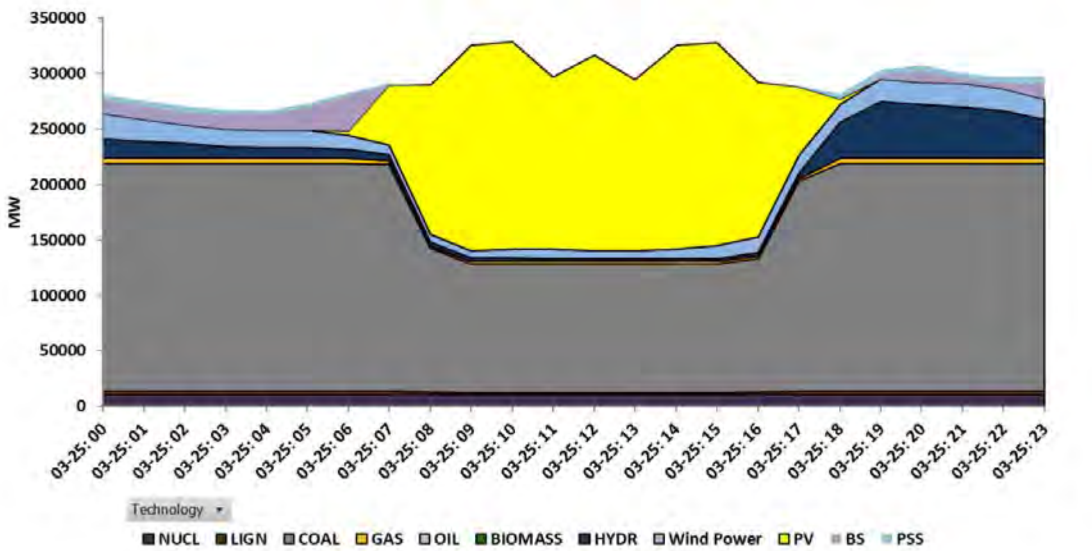
The Levelized Tariffs of Gas-based plants can be further economized with opportunity of Spot Cargoes at cheaper prices. The crude prices below 50 $ /mmbtu in the long run will also help in sustaining the prices of LNG. A mixed strategy of sourcing Term and Spot RLNG so as to bring down the cost would also help to reduce the landed cost and the tariffs. Further, tax comprises more than 20% of the landed cost. The government has recommended to the GST panel to notify Gas under the ambit of GST and if the taxes are reduced, say to just 5 - 10%, the generation cost can come down by 10 - 15%.

c) Capability to meet ramp-up for peaking requirement for Balancing Renewables

The introduction of large scale capacity addition of Renewables, particularly Solar PV requires steep injection of power from other sources when the solar irradiation declines in the evening towards and after sunset. This intrinsic nature of generation curve of Solar PV plants requires matching ramp up from other generating sources, i.e. Coal, Gas, Nuclear, Hydro, to ensure that the demand is met and the power system is safe and stable.

The CEA Draft report on Optimal Generation Capacity Mix for 2029-30 has used ORDENA and other software tools to project the generation capacity mix in 2029-30 as in the Table 1.6.10 Above. Amongst all the scenarios, the maximum ramp would be required on the day with maximum Solar generation, i.e., during the week 23rd March 2030. As per the load profile of 25th March 2030 (refer CEA report on Optimal Mix), the peak solar generation is likely to be around 180 GWs, as in the figure below), and therefore, a ramp up of about 60 GW/hour spread over three hours, would be required from other sources to meet the demand of about 300-310 GW. The CEA report has projected that Battery Storage as well Pumped Hydro Systems would be required to meet the ramp up and meet the peak daily generation as in the figure 1.6.3 below:

Fig 1.6.3: Expected load profile and generation mix on 25.03.2030 (day of Maximum Solar Generation)



(Source: CEA Report on Optimal Generation Capacity Mix for 2029-30)

In its report on 'Flexible Operation of Thermal Power Plants for Integration of Renewable Energy' (Jan 2019) for a detailed examination to ensure power system reliability for the integration of 175 GWs of Renewable energy in 2021-22, CEA had reviewed the ramp-up and ramp-down capability of thermal units. The report affirmed that the existing coal and gas based capacities are sufficient to meet the ramp up in the critical days of maximum solar and renewable generation.

In the above report CEA has assumed a safe ramp-up rate of 1% for the coal based units. The load ramp-up rate of gas–based plants is about two to three times that of coal-based plants. For the year 2029-30, with just 80% of the 267 GWs of coal-based capacity and 80% of the25 GWs of gas-based capacity is on bar, the available ramp up from Coal-based and Gas-based as per CEA norms would be as follows:

Ramp up by 80% Coal Capacity of 267 GWs @ 1%/min : 2,140 MW/min

Ramp up by 80% Gas capacity of 25 GWs @ 2-3%/min : 50 MW / min

Total Ramp up by Thermal (Coal + Gas) : 2,190 MW/Min

Therefore, the ramp up rates of thermal backed up Hydro, can comfortably meet the required ramp-up rate of 1 GW/min (for 180 GWs in three hours). The maximum demand for the day is in the range of 300 to 310 GWs. Out of this, 234 GW can be fulfilled by thermal (coal & gas) alone with only 80% capacity utilization. The rest of the demand of about 70-75 GW can be met very comfortably by remaining sources (Nuclear, Hydro and Wind) without resorting to Battery Storage.

On the day of maximum peak energy demand, i.e., 7th Oct, the peak demand is likely to touch 340 GW. Out of this, about 248 GW can be met from Thermal (coal & gas) operating at 85%. The rest shall be met from combined resource of Nuclear, Hydro, Wind & Biomass.

Ramp up by 85% Coal Capacity of 267 GWs @ 1%/min : 2,270 MW/min

Ramp up by 85% Gas capacity of 25 GWs @ 2-3%/min : 55 MW / min

Total Ramp up by Thermal : 2,325 MW/min

The CEA has projected 300 GWs of Solar and 140 GWs of Wind power by 2029-30. However, if economical and social issues are not addressed in time, it is likely to delays land acquisition and consequently, the capacity addition plans of Renewables may not come up in its entirety. In such a case, generation support from thermal (coal & gas) could meet the ramp up as well as part of the base load during the day-hours. It may also obviate or marginalise the envisaged Battery Storage Capacity in the Optimal generation mix as projected by CEA.

CEA has estimated the typical time required for hot, warm and cold start-up time of Coal and Combined Cycle Gas Turbines (CCGTs). Gas-based are much quicker to respond (refer the table below), and as such the gas-based plants are more suitable for flexible generation and fill up the ramp up during the decline of solar generation.

Table1.6.11: Start-up time for Coal & CCGT

Type of start-ups	Time unit is out of operation	Typical time-coal	Typical time-CCGT
Hot	<8 hrs.	2-3 hrs.	<1.5 hrs.
Warm	Between 8 to 48 hrs	3-5 hrs.	~2 hrs.
Cold	>48 hrs.	5-10 hrs.	~2-3 hrs.

(Ref: CEA report on Fleixble Generation / Jan 2019)

The following aspects also deserve due consideration:

1. **Charging power for Battery System:** The energy made available by avoiding curtailment of Renewable energy may not be sufficient to meet the full requirement of charging power for Battery Storage system on a round-the-year basis. Some cost would be incurred for sourcing charging power for the Battery Storage. It needs to be seen how the developer of Solar PV is compensated for the power supplies for non- curtailment.
2. Hydrogen as a fuel source may need to be considered in view of initiated by NITI AAYOG and Govt of India.
3. **Carbon footprints:** Battery Storage systems are not entirely carbon-free. The charging power supplies sourced from Non-Renewable energy have carbon footprints.

Conclusion:

From the above comparison, it may be drawn that the existing Gas-based capacity has following merits over Battery Storage systems,

- No Capex is required for Gas-based while the Battery Storage system needs significant Capex. Besides, utilization of the existing gas-based capacity, which is presently stranded and facing liquidation, will help the lenders, borrowers and lift the economic sentiments.
- As per the available data, levelized tariffs are higher for Battery storage than Gas based capacity.
- Amongst the thermal capacity, gas-based as compared to coal, is more suited to meet the requirements of flexible generation.
- The existing Gas-based capacity, along with other sources of energy, is adequate for meeting the requirements of flexible generation upto 2029-30.
- Options other than Battery Storge can be explored to avoid curtailment of Renewables.

The key takeaways have been summarized as in the table below.

Table 1.6.12: Comparision of Battery Storage Capacity with existing Gas-based capacity

Parameter	Gas-based	Battery Storage
Capex	Not Required	Rs 7 to 5 Cr/MW
Levelised Tariffs	10.6 to 10.2 Rs/unit	13.2 to 9.9 Rs/unit
Ability for Ramp-up	Adequate	Adequate
Technology	Proven & matured	Developing
Carbon Footprints	Yes	Yes, though lesser.
Relief for Lenders & Burrowers of existing plants	Yes	-

v) Exploring utilization of existing capacity on Merit Order:

As discussed earlier, the markets are witnessing decline in LNG prices. It is imperative that generation costs too decline and become more competitive with other sources of energy. As enumerated in Table 1.6.12 above, there is a difference of about 30-40% between the Variable energy charges of Rail-fed coal stations and that of RLNG-fed gas plants. If this gap is narrowed by reduction of about 20% in

RLNG prices (due to lower benchmarking with crude) and an escalation of 10-15% in coal cost and railway freight over the next 2 to 3 years (as per the escalations considered by CERC in its Approach paper for Draft Tariff Notifications 2019-2024, 75% increase in coal costs and about 50% increase in rail transportation cost between 2009-10 to 2016-17)) , the energy costs at the coal-based plants in hinterland would be similar to RLNG fuelled gas generators.

With the slump in LNG prices, many Spot cargoes have been purchased on 'High Seas' Basis and RLNG has been contracted by Gas-based power station.As per the Generation Scheduling data, towards end of June 2020 on MERIT App, about 7 Gas-based plants with a total capacity of 2180 MWs were scheduled on Merit Order, with Variable Energy Cost from 2.64 to 2.97 Rs/ unit as against Variable Cost of Rs 3.88 to Rs 4.0 /unit at coal-based power plants at Gujarat.

A conservative analysis has been done for the Gas-based plants with F-Class Gas Turbines for estimating Variable Energy Costs while sourcing gas at 3.0 & 4.5 $/mmbtu (DES) at Hazira.After adding Regasification charges, Gujarat Purchase Tax, Marketing Margins, Transportation Tariffs, GST, VAT etc., the energy charges are only about Rs 3.78 to Rs 4.96 per unit.

Table 1.6.13: Variable Energy Charges for F Class Gas Turbines

LNG Price in $/mmbtu DES	3.0	4.5
LT RLNG Foreign Exchange component in USD/MMBtu	3.00	4.50
Regas charges in USD/MMBtu (Rs 51.75/MMBtu)	0.68	0.68
Gujarat Purchase Tax @ 15% on Ex Ter Price (LNG + Regas)	0.55	0.78
Ex-Terminal price in USD/MMBtu	4.23	5.96
GAIL Marketing Margin (Rs 14.36 /mmbtu) in $/MMBtu	0.19	0.19
Transportation charges (assumed as 1 $/MMBtu)	1.00	1.00
GST on Transportation charges @ 12% in $/mmbtu	0.12	0.12
VAT @ 10% in $ / mmbtu	0.55	0.73
Delivered Price in USD/MMBtu	6.10	7.99
Energy Charge Ex Bus (Rs/Kwhr)	3.78	4.96

Assumptions
1 US$ equals 76 INR
Heat Rate assumed as 2000 kcalls/kwhr at Partial Loadings for F Class

It is also worthwhile to consider that taxes comprise about 20% of the landed cost of gas.The government is already planning to bring Gas under the ambit of GST and if the taxes are reduced, say to just 5 - 10%, the generation cost can come down by 10 - 15%. Further, the Heat Rate of the F-Class machines has been taken as 2000 K Cals/khwr to account for partial loading / frequent start stops. If gas-based plants operate at base load, the generation cost can come down by another 10%.

vi) Gas demand projections for Power sector

The scheduling of RLNG-based power would find buyers as its merit order would be competitive. In such a case, the gas-based capacity would operate at 33% to 60% PLF and demand would be as follows:

4 GW of North-East capacity @ 60% PLF	**: 12 -13 MCMD**
7 GW of APM/ PMT based capacity @ 40% PLF)	**: 15 -16 MCMD**
14 GW of Stranded capacity @ 33% PLF	**: 23 -24 MCMD**
Total	**: 50 -53 MCMD**

These numbers are similar to the demand projected by several energy consultants. In its demand projections of gas required for power sector, KPMG has projected a demand of 45 -55 MMSCMD between 2025 and 2030 (as per its assessment of the Oil & Gas sector).As the demand for gas in power sector is price sensitive, we have developed two scenarios for estimating the demand:

Scenario 1: Moderate Demand (Low Crude / LNG prices): It is expected that with the decline in crude and gas prices, energy generation costs would be lower. This scenario would place the gas-based generation capacity to be competitive as compared to Battery Storage. Also, with higher load ramp-up capability as compared to coal-based plants, gas-based capacity would find favour with the system operators for utilising it effectively for balancing the power system and enhancing its reliability. Consequently, the capacity utilization (or the PLF) of gas based plants are expected to increase to about 30% in 2025 and 35% in 2030 and the gas consumption would go upto 47 mmscmd in 2025 and 54 mmscmd in 2030 as in the table below, and with the reduction in Battery Storage and Renewables, this might remain static beyond to 2040.

Table1.6.14 (a) Demand Scenario1: Moderate to low Crude / LNG prices < 5 -6 $/mmbtu: High Demand

High Demand Scenario for Power Sector							
Capacity			**2020**		**2025**		**2030**
Category	**Capacity**	**PLF**	**Demand**	**PLF**	**Demand**	**PLF**	**Demand**
North East	4000	60	13	65	14	70	15
APM Gas	7000	20	7	30	11	35	13
Stranded	14000	15	11	30	22	35	26
Total Demand			**31**		**47**		**54**

Scenario 2: Low Demand (High Crude / High LNG prices > 5 $/mmbtu) It is expected that above 6 $/mmbtu, the generation cost would exceed that of coal-based plants at hinterland, and will eventually result in low schedules as seen in the previous years for the gas-based capacity. Besides, the Government policy of maintaining the share of APM gas for the CGD sector will gradually see to decline in availability of APM gas for power plants. As such, even if gas-based plants find favour with the system operators for utilizing it effectively for ensuring the power system stability, their utilization will not decline further and consumption would sustain at existing levels of 30 – 31 mmscmd.

Table 1.6.14 (b) Demand Scenario2: High Spot prices > 5 -6 $ /mmbtu, Low Demand

Low Demand for Power Sector							
Capacity			**2020**		**2025**		**2030**
Category	**Capacity**	**PLF**	**Demand**	**PLF**	**Demand**	**PLF**	**Demand**
North East	4000	60	13	60	13	60	13
APM Gas	7000	20	7	20	7	20	7
Stranded	14000	15	11	15	11	15	11
Total Demand			**31**		**31**		**31**

1.6.4 (B) Sector wise analysis of demand: Fertilizers

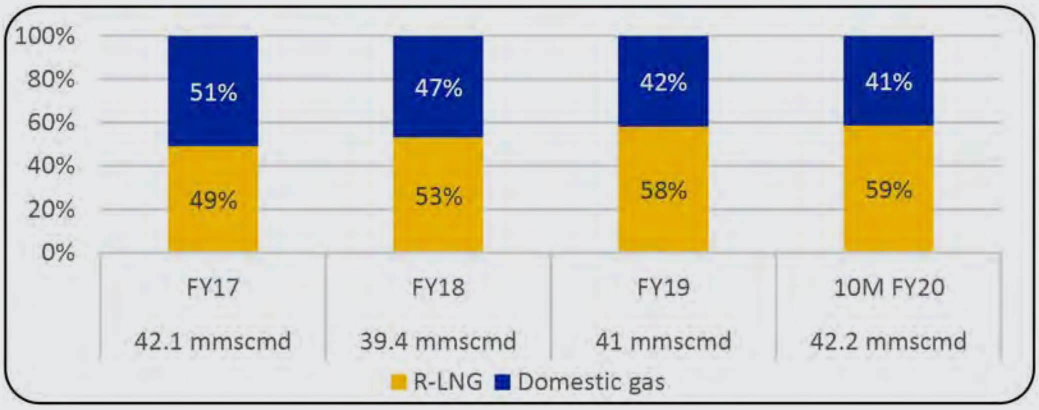
Fertilizers are micronutrients used to increase the fertility of soil and help in higher yield of crops. In view of the large population and agriculture being the mainstay of India's economy for decades, the availability of Fertilizers is a key priority for the country's economy. India is the second largest consumer of Fertilizers behind China. As per the Fertilizer Association of India (FAI), in 2018-19, India consumed about 57 Million MT of Nitogen, Pottassium and Phoshorus- based (N,P,K based) Fertilizers. Urea comprised about 32 Million MT i.e. about 56-57% of the total consumption, out of which about 24 million MT was indigeneously produced and about 7.5 million MT was imported.

The manufacturing processes for Ammonia based and Urea (Nitrogen or N nutrients) fertilizers utilize hydrocarbons like Naphtha, gas as feedstock. The Domestic gas allocations were done by the GoI and Fertilizers always were in the top priority for receiving allocations. The production costs on gas are much lower than Naphtha. Over the years, many Naphtha based Fertilizer plants have been converted to gas.

Fertilizer Sector : Government policies and its impact on RLNG consumption

With agriculture being core to India's economy, Fertilizers are subsidized by the government. As against the average production cost of about Rs 900/- per bag of 45 kg, about Rs 650/- per bag is subsidized. Over the years, increase in domestic demand required fresh capacity additions for Ammonia & Urea. However, by 2012, the shortage of cheap domestic gas compelled the Urea manufacturers to source RLNG to maintain their production targets. The New Urea Investment Policy was approved by CCEA in 2012, wherein, the realization prices of Urea were benchmarked to the import price parity (IPP), subject to a floor and ceiling, which in turn were linked to gas prices. This effectively meant that in a limited domestic gas scenario, Urea production costs from expensive RLNG would be much higher than the imported Urea, leading to impediments in capacity building. Even the existing Fertilizers which were procuring RLNG to make up the shortages in domestic gas supplies, felt constrained due to increase in the RLNG prices which were linked with crude and were fluctuating frequently. In view of the need for encouraging adequate domestic production of Urea, the GoI introduced price pooling of domestic and RLNG for supplies to the Urea Fertilizer plants. To a large extent, the Gas pooling facilitated the sourcing of RLNG to make up for the domestic shortages and fulfil the gas required by the manufacturing plants and helped them to produce at optimum capacity utilization. Besides, it mitigated the risk of uncertainty in realization for the production from new plants which did not have domestic gas allocations and were dependent upon RLNG. Consequently, over the years, the RLNG share in the gas consumption has therefore gone up as brought out in the figure Below

Fig: Trend of growth in the share of RLNG in gas basket of Fertilizers



(Source: PPAC / ICRA)

The government policies helped absorbing RLNG and in the conversion from Naphtha as also in the revival of many old Fertilizer plants on RLNG. However, with increase in RLNG share in the gas basket for Fertilizer plants, the pooled price have increased, and more so in the scenario of rise in crude price. This cost of production of urea would go up and if it exceeds the cost of imported urea, it can result in a negative impact on domestic production, and consequently, gas consumption. On the contrary, in a scenario of low or moderate crude or LNG prices, the pooled price of gas would remain relatively low and which will keep the production cost of indigenous urea more competitive against imports. This scenario supports growth in consumption of gas.

Based on the basis of the future brown field capacity additions and improved capacity utilization, production of gas-based fertilizers are likely to increase by another 4–5 MTPA by 2025. The industry reports by KPMG and ICRA have also forecasted consumption to increase from existing 42 mmscmd to 49-51 mmscmd by Fertilizers during 2025 to 2030, which also matches with the Urea production targets. Assuming moderate growth to replace the import dependency could see capacity additions and gas demand to increase to 55 – 60 mmscmd by 2040

1.6.4 (C) Sector wise analysis of demand: Refineries & Petrochemicals

Refineries process crude by distillation, cracking and other processes to produce a wide range of fuel oils, lubes and other hydrocarbons including petrochemicals. The margins of a refinery depend on the wide range of crude oils it can process and optimum conversion to value added products. The Nelson Complexity Index is a measure of the complexity that enables a refinery to convert even the heavy residues into value added products. For instance, RIL Expansion Refinery at Jamnagar can handle over 150 types of crude and is the first refinery in the world to process the low value pet-coke into Syngas, thereby making it a 'bottomless refinery'. The NCI of RIL Expansion Refinery is 21.1, the highest in the world. The Paradeep Refinery of IOCL and the HPCL Bhatinda refinery have NIC of about 12. However, the processing requires a significant amount of heat. Natural gas provides clean, efficient and more economical source of energy for the refineries. It enables the refineries to achieve higher margins. While few refineries have been using gas, the rest are likely to shift to gas.

In the near term, CPCL, HPCL Vizag & MRPL are soon to shift to gas. Besides, many refineries have embarked on modernization projects for improving higher turnover of middle / high distillates and reduce heavier and low-valued bottoms. They would also need more gas.

Petrochemicals also need gas as feedstock as well as source of heat for the cracking, reforming etc. It is anticipated that in the next three years, all the major refineries and petrochemicals would be connected with trunk gas pipelines. KPMG estimates that the cumulative demand for Refinery and Petrochemicals can go up to 68 MCMD in 2020-21 and reach 85 MCMD in 2025 and 108 MCMD in 2030. A conservative growth of 3.5 – 4% would see the consumption grow to about 145 MMSCMD by 2040.

1.6.4 (D) Sector wise analysis of demand: City Gas Distribution (CGD)

i) Background & growth

In terms of cost benefits, the CGD is an attractive option for end-users in domestic, commercial and industrial segments in terms of offering improved ease of use and fiscal savings for fuel switching to Piped or Compressed Natural Gas (PNG / CNG) from existing fuels. The CGD sector targets three segments of customers, Piped Natural Gas (PNG) for Domestic households, Compressed Natural Gas (CNG) for automobiles and PNG/CNG for Commercial entities and Industry.

While CGD existed in metropolitans and isolated regions with abundant domestic gas, the CGD sector took off after the Petroleum & Natural Gas Regulatory Board was formed in 2007, post the enactment of the PNGRB Act in 2006. Beginning in 2008, the PNGRB brought out a series of regulations for the systematic development CGD sector. In line with the regulations, the PNGRB earmarks the Geographical Areas which attract investors for developing the CGD network. These GAs are put up for bidding by prospective developers or entities. PNGRB then carries out a competitive bidding process for selecting and awarding the 'authorization' to the successful entity. Post award of 'authorizations' the PNGRB monitors the progress of entities and ensures timely completion. It also prescribes the technical safety standards and the obligations to consumers. A list of these regulations can be referred at 1.3.4 (g) above and a gist at Annexure –II in this report.

Till 2014, the CGD sector registered a very ordinary growth. Main reasons were the unavailability of trunk pipeline connectivity and shortage of cheap domestic gas. However, in 2013, in a major court ruling the Courts directed the Government to provide gas at uniform prices for all the CGD entities for Domestic PNG and CNG and maintain the ratio of domestic and market gas across all CGD entities. Subsequent to this award, the MoP&NG issued guidelines for its implementation and compliance. This was followed by the Government intent for improving share of Gas from 6% to 15% in country's primary energy basket. From 204-15, the MoP&NG launched several initiatives for expansion of the pipeline network through PNGRB and by GoI mandate to the PSUs. Meanwhile, the PNGRB also reviewed and revised its bid evaluation criterion and the penal provisions for not achieving the minimum work program. Supported by these measures and the on-going development work on pipelines expansion projects, the CGD became more attractive. In the 9th and 10th rounds in 2018, a total 136 GAs were put up and all of them were bid for. The following table and graphical representation map the overwhelming response for CGD:

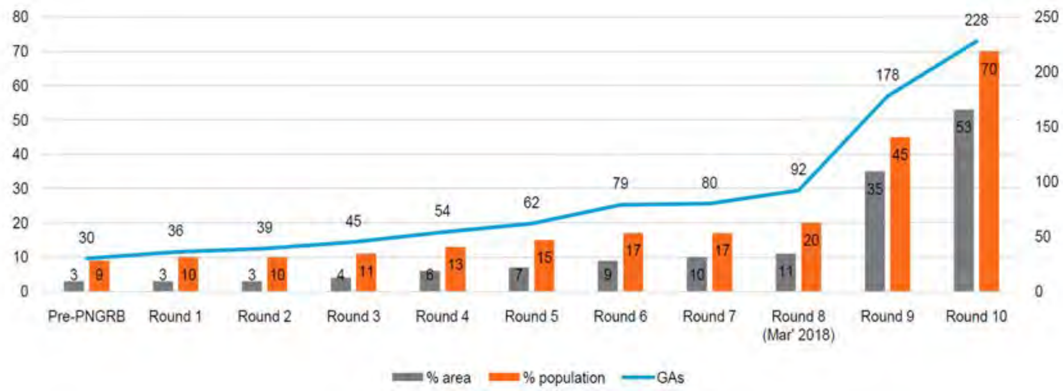


Fig1.6.4: Round wise Geographical Areas and Coverage of population and area
(Source PNGRB)

The growth has picked up and CAGR from 2015-16 onwards is 14% for number of CNG Stations and 16% in the number of PNG connections. The gas supplies have witnessed growth of 80% over the past 21 quarters as mapped in figure 1.6.5. below

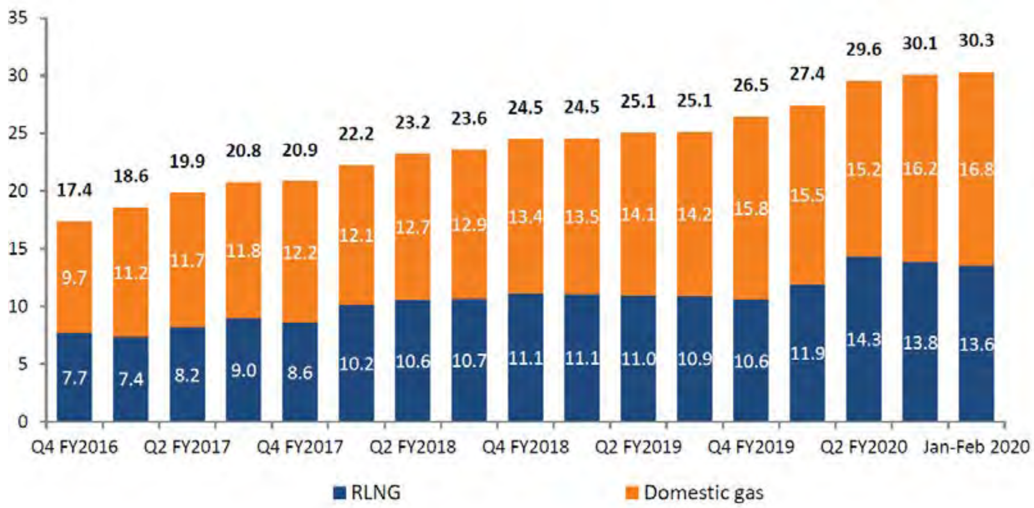


Fig 1.6.5: Growth of gas consumption in the CGD Sector from Jan 2016 to Feb 2020
(Source: ICRA,PPAC)

ii) Benefits to CGD end-users in fuel switch:

Cost benefits: A comparision for cost benefit between automotive fuels brings out that CNG is cheaper by 48% to 58% as compared to High Speed Diesel (HSD), Motor Spirit (Petrol) and Auto LPG. (see table 1.6.15below).

Table 1.6.15: Ccost of thermal energy in CNG, Petrol and Diesel in India

Fuel	Price	Unit	GCV	Unit	Price In INR/1000 Kcals	Price In USD/mmbtu
PNG Comml	44	Rs/cm	10,000	Kcals/cm	4.4	15.20
CNG	50	Rs/kg	12,500	Kcals/Kg	4	13.82
Petrol	72	Rs/Litre	8269	K cals/litre	8.71	30.07
Diesel	63	Rs/litre	9185	Kcals/Litre	6.86	23.69

Notes
1. GCV of Petrol is 11,100 Kcals/Kg and density is 0.745 Kg/litre
2. GCV of Diesel is 11,000 Kcals/Kg and density is 0.835 Kg/litre
3. Exchange rate is 1 USD = 73 INR
4. Conversion from Kcals to btu: 1 K cal = 3.966 btu

Domestic PNG is even cheaper than the Subsidized LPG by over 10% and by 33% as compared to Un-subsidized LPF. LDO just about breaks even and Heavy Furnace Oil (HFO) is cheaper than Commercial City Gas. The competitiveness based in Industry data is as in table below:

Table: 1.6.16: Competitiveness of PNG with LPG and CNG with MS, HSD, LDO & HFO

Traditional Fuels						City Gas				
Fuel	Selling Unit	Selling Price	Gross Calorific Value (GCV)	GCV Unit	Energy Cost (Rs/million Kcal)	Fuel	Selling Price	Selling Unit	Energy Cost (Rs/million Kcal)^	City Gas cheaper on energy terms by
MS	Rs./litre	69.6	8419	Kcal/litre	8271	CNG	45.20	Rs./kg	3587	57%
HSD	Rs./litre	62.3	9036	Kcal/litre	6898	CNG	45.20	Rs./Kg	3587	48%
Auto LPG	Rs./litre	49.8	10800	Kcal/kg	8532	CNG	45.20	Rs./Kg	3587	58%
Sub. LPG	Rs./Cylinder	560	10800	Kcal/Kg	3652	PNG (d)	30.10	Rs./m3	3237	11%
Un-sub. LPG	Rs./Cylinder	744	10800	Kcal/Kg	4851	PNG (d)	30.10	Rs./m3	3237	33%
Bulk LPG	Rs./Kg	77.2	10800	Kcal/Kg	7144	PNG ©	44.42	Rs./m3	4776	33%
LDO	Rs./litre	35.1	8800	Kcal/litre	3986	PNG (I)	37.79	Rs./m3	4063	-2%
Furnace Oil	Rs./kg	28.8	10440	Kcal/kg	2761	PNG (I)	37.79	Rs./m3	4063	-47%

Source: Prices from websites of IOC and BPCL at Delhi, ICRA analysis; Prices as on April 1, 2020
Note: (d): domestic, (I): industrial, ©: commercial. ^GCV of gas assumed at 9300 Kcal/m3.

(Source: ICRA)

The switching cost for the LPG with Domestic PNG is practically negligible. ICRA has worked out the switching costs for consumers on Diesel and MS. It has considered the conversion costs, approximate mileage, maintenance costs, average 15,000 km travel annually, and the break-even comes just after 14,000 kms for cars on MS and less than 4 months for Buses and less than 6 months for Auto. For a 4-wheeler, assuming a life cycle of 10 years and approximate market salvage value, the overall benefit is about 20-22% over the lifetime.

Fig 1.6.6: Lifetime benefits & Breakeven for switching fuels from Petrol / HSD to CNG

	Running Costs (Rs/km)				Conversion Costs (Rs)	Break Even Km	Avg km/day	Break Even Months
	CNG	MS	HSD	LPG				
Car on MS	2.15	5.36			45,000	14,046	50	9.2
Car on Auto LPG	2.15			4.25	30,000	14,282	50	9.4
Bus	9.04		17.81		200,000	22,809	200	3.7
Auto	1.29	2.79			30,000	20,083	100	6.6

Cost of ownership calculations for 4-wheeler	Petrol	CNG	Diesel
Purchase price	600000	645000	730000
Running & Maintenance Cost			
Cost of Fuel (Rs./ltr)	69.63		62.33
Cost of Fuel (Rs/Kg)		45.20	
Mileage (in Km/ltrs or Km/kg)	13	18	16
Cost per Km (Rs./Km)	5.36	2.51	3.90
Life of the vehicle (years)	10	10	10
Average distance travelled per year (Kms)	15000	15000	15000
Running Cost (Rs.)	803423	376667	584344
Maintenance Cost per annum (Rs.)	10000	15000	15000
Salvage Value after 10 years (Rs.)	50000	35000	50000
Cost of vehicle over useful life	**1453423**	**1136667**	**1414344**
CNG lower by, as against petrol		22%	
CNG lower by, as against diesel		20%	

Fuel	Retail Price on Mar 7, 2018	Mileage (Km/litre)		
	Rs/Litre	Taxi/Car	Bus	Auto
MS	69.6	13.0		25.0
HSD	62.3	16.0	3.5	
Auto LPG	49.8	11.7	3.0	22.5

- Economics for end consumers remain strong
- Remain favourable at current CNG and alternate fuel prices

(Source: ICRA)

Ease of use: Piped gas offers an ease and convenience in handling by the end-users. The piped gas supplies do not need any storage and safety concern. Besides, the loss in handling is minimal.

Low carbon footprints: The gas supplies from CGD is 99% methane, which is considerably less emissions than HSD / LDO / HFO.

iii) Benefits to CGD developers: Attractive returns: As per an industry analysis, the EBITDA margin has been more than 20% and upto 57% for the existing CGD companies, except GAIL. This has encouraged investors and developers to participate and post aggressive bids in the 9th and 10th rounds. The attractive returns so far encouraged a high participation by bidders in the 9th and the 10th rounds.

This has also helped to enhance confidence of lenders and speed up Financial Closures of the awarded CGD projects / GA by the month.

iv) New government initiatives Draft CGD Policy to accelerate implementation: Timely implementation of all the awarded CGD networks is the key to achieve the desired penetration of gas as per the policy objectives. Implementing CGD requires land, 'Right-of-Way/Use', permissions / clearances from a number of bodies and other statutory compliances. To overcome the challenges and to speed up the development, a national CGD policy is under consideration of PNGRB. This will provide a structured framework for all the state government and local authorities / bodies / facilitate in help to resolve all bottlenecks in implementation of the projects.

v) Demand projections:

a) CNG & PNG: Supported by the following key drivers for growth, viz 80% growth over last 16 quarters (30.3 in Q4/2019-20 from 17.4 in Q4/2016-17),

- 14% CAGR of CNG stations and for 16% CAGR for new PNG connections, ,
- Targets of the 9th and 10th rounds of CGD aimed to increase PNG consumers from 5.5 millions to 42 millions by 2026,

the demand for CGD has been worked out at 15% CAGR till 2028 , declining thereafter to 10%. The projected demand increases nearly four times from the existing 30 to 112 mmscmd in the year 2030, and six times by 2040 is brought out in the table below

Table 1.6.17: Growth in Demand of CNG

Year	2020	2025	2030	2035	2040
Demand	30	61	112	143	183

b) Bulk Industrial consumers

The gas demand for the Bulk Industrial consumers has grown at a steady annual growth rate of 3-4% in the past years. the growth rate shall be well above the GDP growth rate. The gas as bulk PNG offers a substantial price arbitrage and incentive for switching from diesel as can be seen in the table 1.6.17 Above.

The demand in 2017-18 was about 21 mmscmd as per GAIL. It is expected that with a significant penetration of existing geographical areas and with pipeline network reaching the industrial belts of Ranchi, Jamshedpur and Haldia in eastern India, and Hosur, Bangalore, Mangalore and Trichy in the southern India by end of 2020 or beginning of 2021, a growth rate of about 7% is achievable. From 2023 onwards, the major part of the Eastern and Southern industrial belts can support a growth of 10% till 2030, and subsequently, 5% over the next decade. The industrial demand projections are as follows:

Table 1.6.18: Growth of Industrial Demand

Year	2018	2020	2025	2030	2035	2040
Demand in mcmd	21	24	36	57	73	93

1.6.5: Challenges: Factors affecting demand:

A) Timely completion of Pipelines under construction

Timely completion of the trunk pipelines to the consumers, particularly in South and East India are crucial. The RoU/RoW issues have to be timely addressed for pipeline projects in South (Tamil Nadu) and the East (W Bengal and Orissa). The tie-in pipelines with RLNG terminals also need to be ready before the terminals become operational.

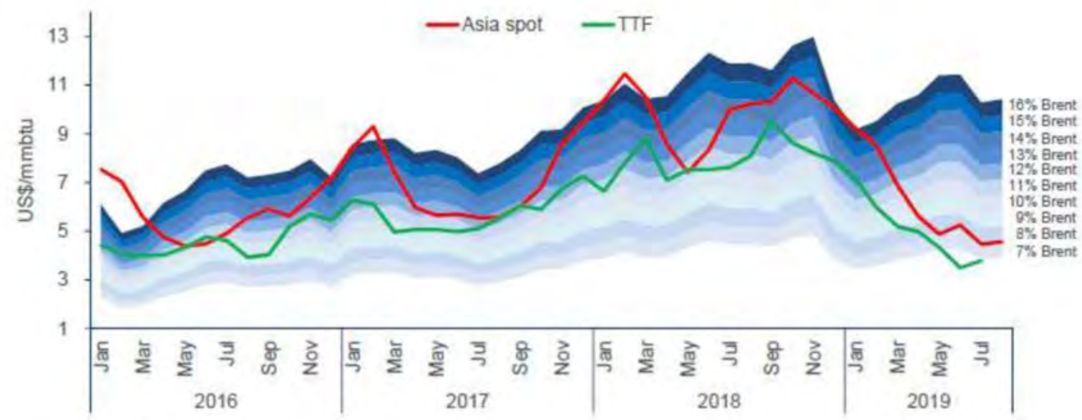
B) Capacity Utilization of the RLNG terminals

RLNG terminals have consistently performed above their nameplate capacity. The capacity utilization has been supported by the substantial Long-term LNG supply agreement. While some of the upcoming terminals have already booked capacities, yet a considerable capacity for many new Terminals have not yet booked and their utilization would depend on the sourcing of short-term or Spot RLNG sourced by the Gas Consumers/Marketers/ Traders/ Terminals.

C) Pricing of RLNG: Term and Spot

Prior to 2016, the Asia Spot LNG and TTF (Netherlands/Europe) gas prices always remained upwards of 14% parity with crude. As per Wood Mckenzie (refer Fig 1.6.7 below), post 2016, the availability of more short-term / Spot cargoes have eased the prices and by mid of 2019, the prices were a mere 6-8% of crude parity.

Fig 1.6.7: Asia Spot and TTF prices at corresponding parity with Brent



(Source: Woodmackenzie)

The challenge is to negotiate for Term LNG at lower crude parity or a basket of Gas & Crude indices.

1.6.6 Demand Summation: Scenario mapping

Based on the drivers for growth, sectoral analysis and the challenges as deliberated above, the demand scenario emerges as follows:

A) Demand Scenario-1: Reference Scenario

This scenario is based on low / moderate LNG spot prices as prevailing for the past 2-3 years. It assumes crude to remain well below 50 $/bbl. It also assumes a spike in demand from power, industrial and other sectors.

Table 1.6.19a: Reference Demand in Low/ moderate Crude & Spot LNG Prices

Scenario 1; Reference Demand				
Sector	**2020**	**2025**	**2030**	**2040**
Power	31	47	54	54
Fertilizer	44	49	51	55
Refineries/Petrochems	68	85	108	145
Bulk Industrial	24	36	57	93
CGD	30	61	112	183
Total	**197**	**278**	**382**	**530**

(Author's Research)

B) Demand Scenario 2: Low Demand due to High Crude / LNG

This scenario foresees high crude prices more than 50$/bbl and LNG prices remaining above 6 $/mmbt. This would result in higher prices for Petrol, HSD, Fuel Oils & LPG. It is unlikely to impact the demand from consumers of sectors like Refineries, Fertilisers, CGD or Bulk Industrial. Only the demand for the Power sector Crashes as high Variable Charges lure away Discoms to coal-based power from Non Pit-head plants in hinterland.

Table 1.6.19b: Low demand in High Crude/ Spot LNG prices

Scenario 2: High Crude / LNG prices				
Sector	**2020**	**2025**	**2030**	**2040**
Power	31	31	31	31
Fertilizer	44	49	51	55
Refineries/Petrochems	68	85	108	145
Bulk Industrial	24	36	57	93
CGD	30	61	112	183
Total	**197**	**262**	**359**	**507**

(Author's Research)

1.6.6 Demand – Supply Gap & analysis

As discussed in the previous paras, the demand-supply gap is being projected in two scenarios:

A) Reference Scenario: (Low Crude / Surplus LNG, Domestic gas production profile as planned, High Demand): This scenario will find demand rising mainly from the power sector.

Table 1.6.20a Demand- Supply Gap: Reference Scenario

Demand- Supply Gap: Reference Scenario (Low Crude, Surplus LNG , High Demand)				
	2020	**2025**	**2030**	**2040**
Demand	197	278	382	530
Supply	166	341	374	433
Gap	31	-63	8	97

B) Conservative Scenario: (High Crude/LNG prices, low domestic gas production and suppressed demand): This scenario will see significant erosion of demand from power sector. The demand supply gap is as follows:

Table 1.6.20b: Demand- Supply Gap: Conservative Scenario

Demand- Supply Gap: Conservative Scenario (High Crude / LNG prices, low demand)				
	2020	**2025**	**2030**	**2040**
Demand	197	262	359	507
Supply	166	316	338	380
Gap	31	-54	21	127

Analysis:

- The shortages in 2020 may not actually occur due to the slowing down of economy as an impact of COVID 19.
- There are surpluses in 2025, which can be utilised for trade.
- The apparent shortages in 2030 and 2040 can be easily met by enhancing utilisation of RLNG Terminals and by brownfield expansion.. The RLNG terminals have technical capability of vaporising more gas than its name plate capacity. Dahej terminal has successfully operated above 100% for several years. The scenario had assumed only 75% capacity utilization in 2030. An increase of 5% in capacity utilization will make about 14 MMSCMD of additional gas, and a 10% increase will result in an increase of about 28 MMSCMD of gas which should be sufficient to generate surpluses which can e used for trade in 2030. For meeting the demand beyond 2030, brownfield capacity expansion of upto additional 5 MTPA capacity per annum can be supported by FSRUs alone or can be planned with a mix of expansion of terminals and FSRUs.

1.7 Gas Trade Development of Gas Hubs / Exchange

1.7.1: Gas Exchange and Hubs

A) Benefits of an Exchange: The existing supply contracts have little flexibility in variation of flow rates and the supply quantities (daily/fortnightly/monthly/annual) between consumers and sellers. The contracts do not permit revision in daily allocations by the consumers, except in very special cases. Also, for any incremental demand, considerable time is required for negotiations and settlement. Many a times, the consumers are not aware of volumes available with other sellers. A Commodity Exchange with Natural Gas in its portfolio, is a 'marketplace', and essentially a virtual location identified for any physical deliveries and title transfers for a variety of duration-based contracts i.e., Day-ahead, Daily, Weekly, Fortnightly, Monthly etc. At times, the consumers also look for mitigating the risks of future escalation in prices and look for risk mitigation. The exchange provides a portfolio of products like futures and derivatives for hedging their risk. It provides the following benefits for the buyers and sellers:

- **Access:** Provides a platform for all the buyers/their clients, sellers/their clients, traders.
- **Standard Contracts:** It offers standard contracts for supply and transmission of gas.
- **Minimum denomination of trade**
- **Multiple Products for spot deliveries and derivatives for hedging risk.**
- **Dynamic settlement of demand & supply**

B) Gas Hubs and their relevance to development of Trade / Gas Exchanges: Gas Hubs are the important nodes in gas pipeline networks where multiple pipeline of gas supply or evacuation owned by multiple pipeline owners are connected. It helps to square off daily imbalances in physical quantities. The physical availability of suppliers and pipelines help in using a hub as a central pricing point. The transportation costs from hub to the metering point at buyer's end are an add on for the buyers. This is why the Markets / Exchanges need a hub.

Developing a hub essentially needs multiple suppliers from domestic producers to pipeline imports or supplies from an LNG Terminals. It also needs some storage / buffer or a source capable of flexible production or supplies to meet the variation in demand at short notice. If there are only one or two suppliers, then the hub becomes a Monopolist marketplace. The buyers also need to be from diverse interest like power, petrochems, household, industrial to evolve competition. The regulations should be minimal and supportive to suppliers from domestic or foreign markets and fair contracting procedures. Development of a Hub also requires assurance of minimal political interference by governments at behest of one or more sections of consumers. Therefore, development of a hub takes time, support from buyers, sellers, government and regulators.

C) Key Hubs: The 'Henry Hub' in Louisiana State of the USA is the worlds oldest and the largest gas distribution hub. Presently, it connects nine interstate pipelines and four intra-state pipelines. The network of pipelines connecting it to rest of the country and across to Mexico and Canada, multiple suppliers, access to a gas storage cavern, a transparent settlement system for transmission and sale and purchase of gas, and open accessibility underpin its emergence as an established index for gas prices for trade. Henry Hub indexed Monthly Futures trade commenced on NYMEX in April 1990. In Europe, National Balancing Point in UK had pipeline connectivity with North Sea Gas as well as LNG and a storage facility and was the established hub till recently. With the decline in gas production in the North Sea, the Dutch TTF (Title Transfer Facility),, based on its portfolio of offerings, volumes and churning (with similar infrastructure of interconnecting pipelines, storage and an LNG terminal, , has emerged as Europe's popular gas hub.

As mentioned above, Natural Gas is traded internationally on the commodity and stock exchanges i.e. NYMEX, NYSE, NASDAQ, LSE, EEX based on the prices indexed with a 'Hub'. However, Asia is yet to develop a gas hub which can gain credibility for its index and can be traded.

D) Policy initiative by Government of India for developing Gas Exchange and Hubs: In line with its policy to expand gas-based economy, the Central / Federal government has supported investments in upstream Exploration, Pipelines, and Consumer outreach. The country plans to achieve "One Nation One Grid', the government has declared its intention to invest in gas infrastructure and facilitate Gas Exchange. (Refer Press Release / PIB Dt 28.12.2018).

In addition to the above, the government has planned the following policy initiatives:

- Establish a Transmission System Operator (TSO) for transparent access by suppliers & consumers and efficient utilization of the pipeline capacity.
- Establish Gas Exchange / Trading Hubs
- Establish pipeline connectivity and expand trade of hydrocarbons with neighbouring nations (like Bangladesh, Myanmar, Srilanka etc).

On 1st July 2020, under the PNGRB Act, the Government has assigned to the PNGRB the function of regulating the establishment and operations of gas trading hubs for equitable distribution and increased availability of gas. Accordingly, PNGRB has come out with the draft regulations in July 2020, inviting comments from all stakeholders.

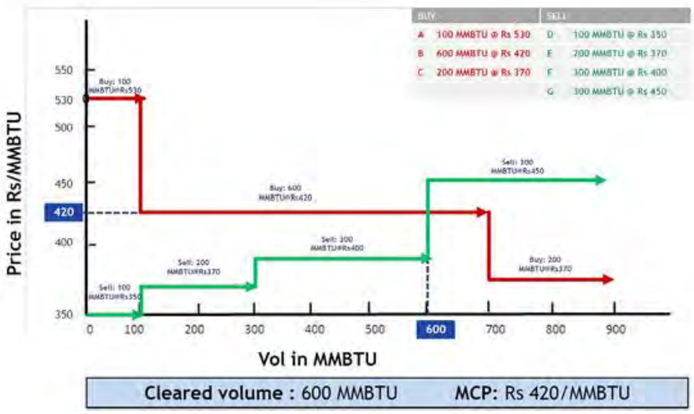
1.7.2: Indian Gas Exchange (IGX):

In Feb 2020, India Energy Exchange (IEX) Ltd has launched the first Gas Exchange in the country where in liquid trade for gas can be carried out amongst registered members. The company operates the largest Electricity exchange and as in Feb 2020, it had over 6600 participants eligible to trade electricity, 56 Distribution companies (Dicoms), over 4200 Open Access consumers, and over 200 Generators for electricity trade as also the Renewable Energy Certificates (RECs) and Energy Saving Certificates (ESC). The IEX has over 12 years of experience in Electricity trade. Over the years, the exchange has different portfolio of offerings like Day-Ahead Market (DAM), Term-Ahead Market (TAM), RECs, ESCs.

IGX has partnered with GMEX, UK to develop the trade platform for the exchange. The salient features being offered by IGX are as follows:

- **Route based transmission pricing:** In line with the existing Zonal tariffs.
- **Four physical hubs:** To begin with, four physical points of trade identified viz. Dahej (Ex RLNG terminal), Hazira (Mora interconnection point), Odugu and KG Basin
- **Six Trading Products:** A Day-ahead, Daily, Weekly (7 day), Weekdays(5 Day), Fortnightly and Monthly
- **Lot size & Price:** Minimum lot is 100 mmbtu priced in INR/mmbtu
- **Price Discovery:** Double sided auction, Bids collected during the call period and then matched. Illustration from IGX is as below:

Fig1.7.1: Illustration of the Price Discovery



(Source: IGX)

- **Delivery:** Delivered Transactions (Gas plus Transmission Capacity) and Ex-Hub Transactions (Only for gas, Buyer to tie up Transmission Capacity with Pipeline owners)
- **Imbalance Management:** Out of exchange for Ex-Hub transactions.
- **Contractual Agreements:** The standard agreements required have been hosted on the web-site. Generally, they address the following:
  - Market rules and bylaws Agreement: Seller and Buyer with IGX
  - GTU for Delivered Transaction: Between Transporter and IGX
  - GTU for Ex-Hub Transmission: Between Buyer and Transporter

The exchange has commenced trade from 15th June 2020.

1.7.3 Government outreach for trade of gas with BBINS countries

The Indian government has initiated several initiatives of outreach to neighbouring countries for cooperation in Oil & Gas. Some of these are as follows:

Bhutan: India supplies Petrol, Diesel, Bitumen, coal and a quota of subsidized LPG cylinders. India imports hydro power from Bhutan.

Nepal: India meets the entire requirement of petroleum products and coal. In Sep 2019, a 69 km long pipeline for petroleum products has been commissioned from Motihari , India to Amlekhganj, Nepal. The pipeline will transport upto 2 MTPA of petroleum products. The electricity grid of both countries are connected at several points for Cross Border Electricity Trade (CBET).

Bangladesh: India and Bangladesh have agreed for interconnecting their gas pipeline links at Satkhira border points.

1.8 Summary of the key drivers for growth of India's Gas sector

The following key drivers emerge from the analysis of environment of Gas business in India ;

1. Supportive Government Policies for investments in E&P
Pricing freedom for CBM, Deep Water, Ultradeep water, High Pressure-High Temperature Gas fields, Discovered small fields, Difficult Gas fields and a policy for review of PSCs with minimal interventions.

2. Development of an interconnected National Gas Grid
Laying of pipelines require considerable Capex and is the key enabler for consumers to access or source gas. The government has committed fiscal support in the form of providing Viability Gap Funding for difficult pipelines. A coordinated and acceptable shift from 'Zone-based' to 'Unified' pipeline tariffs is being deliberated at PNGRB. This would help the consumers at the last mile end to be price competitive in their energy consumption. and budgetary support in the growth of Pipeline Infrastructure. This will also accelerate the penetration of the CGD network in the consumer base.

3. Potential of CGD
With the overwhelming response in the 9th and the 10th rounds of bidding by PNGRB for the CGD, the authorized 228 geographic areas (GAs) can effectively provide access to nearly 70% of the country's population in 53% area of the country. The return on investment has been very attractive and Government policy for maintaining the ratio of domestic gas and the RLNG also support the potential of this sector.

4. Capacity addition of LNG receiving terminals
The capacity of country's LNG receiving terminals under construction / expansion is slated to increase from 23.5 MTPA in FY 2019-20 to 66.5 MTPA by FY 2025-26. This will boost the country's capability to import and consume gas.

5. Policy decision for formation of a central gas transport system operator (TSO)
A government task force for improving the share of .gas in primary energy basket has recommended the formation of a central gas TSO for accelerating Intra and Inter-Regional access to gas for consumers across the country.

6. **Modifications in Regulations by PNGRB to attract investments in downstream sector.** Over the past few years, he PNGRB has engaged intensively for modifying the regulations to address the concerns of stakeholders. This has improved the investment sentiment.

7. Taxes

The government is planning to bring gas under the GST regime. This will avoid multiple taxes on Intra and Inter-state sales, legal disputes as well as enable consumers like power plant to claim input tax credit.

8. Development of Gas Exchanges

The first gas exchange, IGX, has commenced operating from 15th June 2020. Meanwhile, in line with the government directives issued as per the PNGRB Act, the regulatory board has issued draft regulations for regulating the functions of Gas Exchanges in July 2020.

Oizmendi Multi-Product Bunker Delivery Vessel - Courtesy of Itsas Gas Bunker Supply S.L.

Chapter 2: Gas and RLNG Environment in Bangladesh

2.1 Key demographics of the energy sector

Bangladesh is the second largest growing economy of the BBINS region. As per the World Bank, its per capita GDP was 1856 $ in 2019. From 2012 to 2018, growth in its GDP and energy consumption matched that of India. In 2019, its GDP growth rate at 8.1% was ahead of India. As per the pre-Covid estimates of ADB, its GDP growth rate in 2020 was expected at about 8.0 %, ahead of its South Asian neighbours, India (7.2%), Bhutan (6.2%) and Nepal (6.2%). While it has always been in the list of UN's Least Developed Countries, its population below poverty line has diminished from 72% to only 10% in 2018. As per Bangladesh Power Development Board, the Grid-connected generating capacity has grown from about 4.2 GW in 2009 to 18,961 GWs in 2019, 60% of it coming from the private sector. The capacity including captive and RE is about 22,562 GW. The per capita consumption in 2018 was about 375 kwhr and nearly 95% population has access to grid connected power.

Bangladesh has about a fourth of India's proven gas reserves, but produces almost similar volumes of Natural Gas. It has a growing demand for gas supported by network of pipelines connecting consumers across all divisions and districts.

As per a report in 2015 on Energy Economics by the Hydrocarbon Unit, Government of Bangladesh, Natural Gas has the highest share of about 48% in the Primary Energy basket followed by Biomass (30%), Oil (16%), Coal (1.6%) and Hydro (2%) as in the table 2.1.1 below:

Table-2.1.1: Bangladesh's Primary Energy Consumption 2018

Source	MTOE	Share (in %)
Coal	2.7	6
Crude / Petroleum	6.9	15
Gas	22.8	48
Nuclear	0	0
Hydropower	0.5	1
Renewables	0.5	1
Bio mass	13.6	29
Power Import	0.5	1

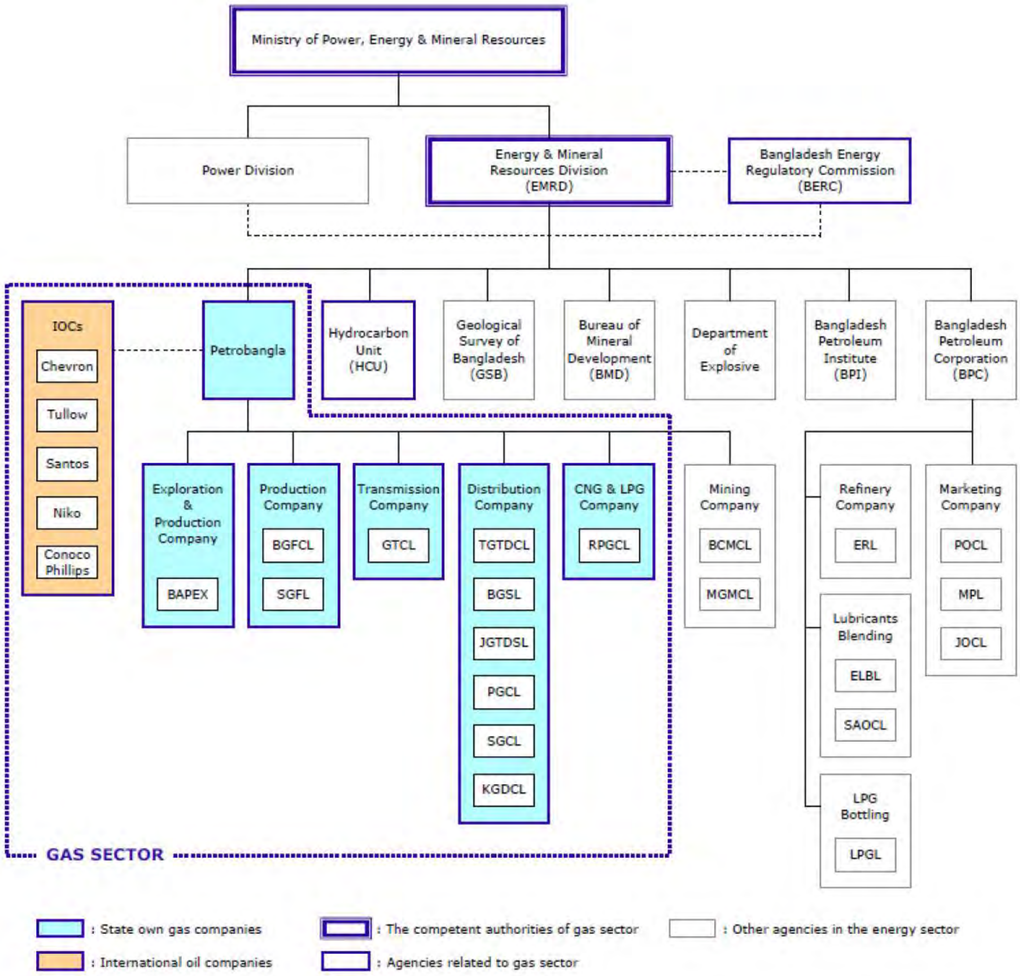
Source - HCU, Govt of Bangladesh

In the Commercial Energy consumption, share of gas was 69% followed by Oil (23%), Coal (6%), Hydro (1%), and Import of Electricity (1%).

2.2 Organogram of Hydrocarbon Sector

Policy and regulatory control of the Upstream, Midstream and Downstream sectors are under state control. The broad structure of the sector is as follow:

Fig 2.2.1: Organogram of the Oil & Gas Sector



(Source: GSMP 2016 , JICA)

Energy and Mineral Resources Division (EMRD) of the Government controls the Hydrocarbon (Oil, Gas & Coal) as well as Minerals (mainly Graphite). Petrobangla is the main Upstream PSU and has under its wings Upstream E&P, production, transportation, distribution & marketing companies. Bangladesh Petroleum Exploration & Production Co Ltd (BAPEX) is the key exploration and drilling company. Bangladesh Gas Fields Co Ltd (BGFCL) & Sylhet Gas Fields Ltd (SGFL) are the gas producing subsidiary companies of Petrobangla. BGFCL has six operating gas fields. SGFL has five gas fields.

Gas Transmission Pipeline Company or GTCL is the gas transportation company operating under Petrobangla. GTCL plans, designs, constructs and operates the pipeline infrastructure. Petrobangla also has six operating companies for downstream supply and marketing for six Geographical areas namely, Titas (TGTDCL), Bakhrabad (BGDCL), Jalalabad (JGTDCL), Paschimanchal (PGCL), Sunderban, (SGCL) & Kanafuly (KGDCL).

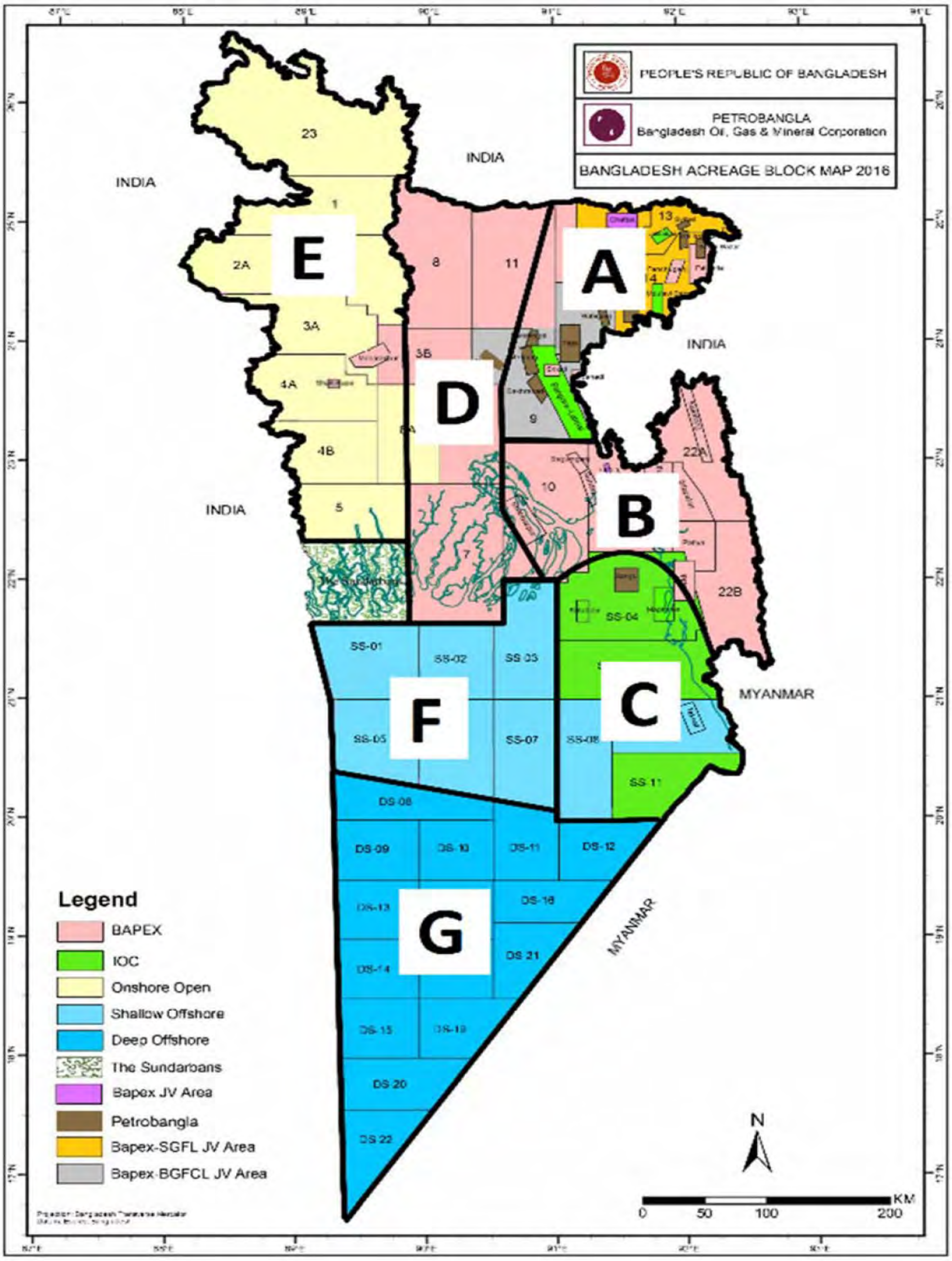
The CNG business and the RLNG FSRU/Terminals are controlled by the Rupantarita Prakritic Gas Company Ltd (RPGCL). Petroleum products like Petrol, Diesel, Aviation Fuels, Kerosene etc are produced by fractionation of gas condensates by the NOCs and some private entrepreneurs. Remaining requirement is made from imports by the Bangladesh Petroleum Corporation under Energy & Mineral Resources Division of the government.

2.3 Regulatory environment and policies for E & P

2.3.1 Bangladesh Sedimentary Basins:

Bangladesh is endowed with the rich Ganges and Brahmputra delta. The sedimentary basins (excluding the Sunderbans mangroves) have been divided in blocks seven geographic areas (A to G). These areas have been further sub-divided in several blocks. The Fig 2.3.1shows these areas and the blocks for exploration, including the blocks under exploration (by the government-owned and IOC) as also the 'Open' blocks, both On-shore and Off-shore area, (Shallow as well as Deep Water)

Fig-2.3.1:Geographical areas (A to G) based on present exploration activities



(Source: Petrobangla, PSMP)

2.3.2 Policies and Initiatives for Upstream Exploration & Production

A) Background: A brief history of oil & gas exploration

Pre – 1971: In 1867, just 7 years after Col Drake discovered oil in Pennsylvania, the first oil discovery occurred accidently in Brahmputra basin in the North-East India. Taking cue, several exploration programmes were launched in geological areas of the Brahmaputra basin located in present Bangladesh. The initial exploratory efforts didn't lead to any major commercial discoveries. In 1947, on partition of India, East Pakistan (now Bangladesh) was carved out of eastern India as part of a new nation, Pakistan. The Exploration activities in East Pakistan were taken up by the Pakistan Petroleum Ltd (PPL), and several IOCs like Shell, Standard Oil and Burmah Oil. In 1955, after nearly five decades of exploratory perseverance, the first discovery was made by PPL followed by five gas & oil fields by Shell.

1971 - 1980: In 1971, East Pakistan was liberated and Bangladesh came in existence as a new country. Petrobangla emerged as the NOC and took over the producing assets of PPL. In 1974, under a new exploration act, Production Sharing Contracts were signed with many IOCs including ARCO, Ashland, Canadian Superior, BODC (Japex), Union Oil and Ina Naftaplin. Oil & Gas Exploration continued with 32,000 km of Gravity, Magnetic and Seismic surveys in several blocks. While 7 wells were drilled, only one discovery was made Off-shore near Kutubdia by Union Oil (later Unocal and now Chevron). By 1979, all the blocks were relinquished, without much success. Meanwhile, in 1975, as an outcome of a landmark deal, all gas producing assets of subsidiaries of Royal Dutch Shell in Bangladesh were transferred to the NOC, Petrobangla and thereafter, all gas-producing assets effectively came under the ownership of Bangladesh.

1980 -1995: First round of Licencing: In 1980, Bangladesh launched a fresh round of PSCs. Between 1981 and 1986, 12 wells were drilled and 7 discoveries were made. In 1989, Bangladesh Petroleum Exploration and Production Company Ltd (BAPEX) was formed by abolishing the Exploration Directorate and as a subsidiary of Petrobangla. The objective was exclusively focus on accelerating exploration and drilling. The subsequent exploratory activities by BAPEX alongwith Shell & Scimitar Corp witnessed a mild success, notably the discovery of the Jalalabad Gas Fields by Scimitar.

1997 – 2007: Second round of Licencing: In 1996, Bangladesh came out with a new Model PSC. Total 11 Blocks were identified and IOCs were invited to participate. This phase, which witnessed exploration of 4 Blocks, culminated in the development of four key discoveries,i.e., Moulvibazar, Sangu, Bibiyana and Jalalabad gas fields. The first 3D Seismic survey in Bangladesh was carried out in the appraisal of the Bibiyana gas fields, which is the largest gas field till date. This phase is the onset of the golden era of gas sector of Bangladesh. In the late nineties, fresh rounds of E&P under PSCs were introduced and four blocks were taken up by IOCs (Shell, Tullow, Cairns Energy, Unocal, Chevron & Texaco) with active participation of BAPEX. The Bangura Gas field were discovered and after 3d Seismic survey was appraised and developed for production.

2008 - 2012: Third round of Licensing: A fresh Off-shore round was launched for the Deep-water blocks. The blocks were awarded to Conoco Philips. However, due to a Maritime dispute with Myanmar and India over block boundaries, nothing much could come out of this round. The blocks taken up in this round were relinquished in 2012.

2012 - 2016: Fourth round of Licencing: In 2012, Bangladesh was successful in getting the dispute resolved in its favour by the International Tribunal for the Laws of Seas (ITLOS) and thereafter launched another round for Off-Shore PSCs with new block boundaries. This round saw considerable interest and PSCs were signed for three blocks, for two blocks with a consortium of ONGC Videsh Ltd (OVL), Oil India Ltd (OIL), & BAPEX, and another block with consortium of Kris, Santos & BAPEX. Drilling of four Off-shore wells is mandatory in the exploration of each of these blocks and the timelines have been extended till 2021.

As a result of the prolonged exploration activities spread over a century, the sustenance and perseverance has paid off in a fair success rate with one in three wells striking producible discoveries. As in 2019, about 21 out of 27 discovered fields, with ownership spread across NOCs and IOCs were still producing gas.

B) Upstream Exploration:

As mentioned above at para 2.2, Petrobangla is the National Oil Company with three subsidiaries for exploration & production, namely, Bangladesh Petroleum Exploration and Production Company Ltd (BAPEX), Bangladesh Gas Fields Co Ltd (BGFCL), Sylhet Gas Company Limited (SGCL). In addition to these, there are IOCs also in exploration and production, mainly Chevron, Tullow, Cairn, Niko, POSCO (S Korea), KrisEnergy, Santos, ONGC Videsh td (OVL) & Oil India Limited (OIL).

The Off-shore blocks take a minimum of 8 to 10 years to commence production if the discoveries are appraised and found commercially viable. The delay in launching the off-shore blocks for E&P has delayed the plan for exploitation of new gas fields and discoveries. The existing fields are depleting.

2D & 3D Seismic Survey: As per the report on Energy Scenario 2017-18 compiled by the Hydrocarbon Unit, eastern folded belt and the surrounding areas are prospective for the exploration activities. Based on the geo-scientific studies, the middle part of the country also has high potential for exploitation of hydrocarbons. The ever growing shortage of gas and decline in domestic production are reasons for more aggressive exploration activities. All possible leads emanating from the available geological data is being studied for prospective interpretation.

In 2017-18, a work program for carrying out 3600 Line KM of 2D Seismic survey has been approved and undertaken. The prospective leads have been identified for taking up wells exploration. Similarly, another initiative under 'Vision 2021' Program has proposals for 3,000 Line KM of Line Survey in addition to drilling of 19 exploratory well are targeted under 'Vision 2021'. The government has also approved a project worth 247.7 Cr Takas for BAPEX for undertaking collection of 3D Seismic data of over 2,700 sq kms, followed by drilling of exploratory wells.

Drilling & Workover: Drilling activities have been undertaken in several exploratory wells of several projects including the Rupakalpa-1, Rupakalpa-2, Rupakalpa-4 blocks. Workover activities have also been taken up in several projects with fair success and production of about 65-75 mcfd were added in 2017-18 as a result of the workover of these wells.

The NOCs under Petrobangla (BAPEX, BGFCL & SGCL) and the IOCs have drawn an ambitious programme to enhance the production by 408 mmscfd by drilling new wells and completing work-over of existing wells. A total of 56 wells have been identified for the same as in the table below:

Table-2.3.1: Year-wise Programme for Drilling & Work-over for augmenting Gas Production

FY	Exploration wells	Development wells	Work-over wells	Total wells
2016-17	2	4	11	17
2017-18	2	1	7	10
2018-19	3	-	11	14
2019-20	2	-	5	7
2020-21	3	1	4	8
Total	**12**	**6**	**38**	**56**

(Source: Petrobangla AR 2018-19)

C) Bangladesh Energy Regulatory Commission (BERC):

In 2003, an Act was passed for the formation of the Bangladesh Energy Regulatory Commission (BERC). The Commission was formed in April 2004. In line with the objectives of the Act, BERC is responsible for issuance of all licences in the Electricity, Oil & Gas sectors. The tariffs for gas, petroleum products, electricity generation, transmission, distribution and storage are decided by the BERC. The BERC is also to advise the government on any matter related to development of the energy sector. It is also responsible to introduce and encourage energy audits and efficiency in energy sector, both, on supply-side as well as demand-side.

The BERC periodically reviews and determine the gas tariffs. The Gas Distribution companies submit to Petrobangla the estimates of the anticipated sales forecast and revenue. Petrobangla also collects all expenditure inputs from the upstream companies. These are submitted to BERC. BERC also take inputs from all stakeholders including the government ministries, sector experts, leading economists, independent research bodes etc. After detailed hearings and deliberations, BERC revises the gas tariffs.

2.3.3 Midstream and downstream: Gas

As explained in the Organogram of the sector at Para 2.2, the Upstream, Midstream and Downstream of the Gas sector operate under Petrobangla. The main operation companies are:

A) Midstream: The Gas Transmission Company Limited (GTCL) is the entity responsible for gas pipeline transportation. The key activity is to plan the transportation infrastructure across the country. It utilises software tools to simulate the projected demand and supply in different zones / nodes of the country and plan the augmentation of pipelines and related infrastructure (like compressor stations etc.) to meet the demand and ensure the supplies are not constrained at any node. It operates the pipeline network, supported by a SCADA and telecommunication system for realtime monitoring.

B) Downstream:

(i) Gas Distribution & Marketing: The country is divided in six zones and they are independently looked after by six Zonal Distribution Companies, namely, JGTDSL, KGDCL, TGTDCL, BGDCL, PGCL & SGCL. A map showing their geographical domains as in the figure 2.3.2 below:

Fig 2.3.2: Zonal Distribution Companies and their geographical areas

(Source: Petrobangla)

(ii) CNG & LPG: Rupantarita Prakritik Gas Company Limited looks after the CNG, LPG and FSRU business.

2.3.4 Midstream and downstream: Oil Refining and Marketing

The Bangladesh Petroleum Corporation, under the Energy & Mineral Resources Division of the Bangladesh Government, is the nodal organization in the petroleum sector responsible for import of crude oil and products, their refining and marketing and exports of the finished petroleum products. Till 1997, the entire sector was a monopoly of BPC. In 1997, the government permitted one private player to enter the fractionation of gas condensates extracted from natural gas fields along with gas. Presently, the fractionation of gas condensates are being done by small scale fractionating plants of Petrobangla, BPC and several small scale Private entrepreneurs.

Petroleum products comprise nearly 22% of the commercial energy consumption. In 2017-18, Bangladesh consumed about 6.95 Million MT of petroleum products. HSD alone had a share of about 70%. The domestic consumption of LPG was about 0.55 Million MT.

The Transport sector was the highest consumer of Petroleum products, with a share of about 50% followed by Power (27%) and Agriculture (16%).

2.4: Gas Reserves, Production, Allocation and Pricing/Tariffs

2.4.1 Natural Gas Reserves

Bangladesh has estimated sedimentary basins spread across 207,000 sq kms within its territories. Between 1910 and 2014, it had drilled 81 exploratory wells. The exploration well count therefore, represents a low drilling density. The country has planned for 53 exploration wells between 2016 and 2021 to be drilled by the NOCs and IOCs. While 52% wells were reported dry, the remaining had hydrocarbon shows. The discovery rate is about 36%, which translates to success of one in three wells, which is very encouraging. However, the discoveries have been small in volumes. Besides, the discovery rate is in the past. Further, the majority area has not been explored or is underexplored.

As per the Society of Petroleum Engineers, reserves can be classified as Proven, Probable or Possible reserves. Proven (or 1P) Reserves are those with reasonable certainty of being produced and commonly accepted as P90 Reserves, i.e., only 10% probability that production will be less than the reserves. 'Probable' (or 2P) Reserves are accepted as reserves with only 50% probability that the production would be less than reserves. The remaining reserves below 50% and above 10% certainty of being produced are called Possible (or 3P Reserves).

As per BP Statistical Review, Bangladesh had proven reserves of about 14 tcf by the end of 2009. However, the Reserves to Production (R/P) ratio is quite low (i.e. 4.2), and as per this report, the Reserves at the end of 2019 were only about 4.3 tcf.

Petrobangla and other bodies like Hydrocarbon Unit of the Energy and Mineral Resources Division use the '2P Reserves' for their assessment of remaining production in their reports. As per the report on Energy Scenario 2017-18 by the Hydrocarbon Unit, As in June 2018, the Proven plus Probable (2P) Reserves were about 28.69 tcf out of which about 15.96 tcf had been produced and only about 12.72 tcf of recoverable Proven plus Probable (2P) reserves were available. Some key information about its domestic Natural Gas sector are tabulated in the 'Energy Scenario 2017-18' is as follows:

Table-2.4.1: Key data on Gas Production and Reserves in 2017-18

Total number of gas fields	26
Number of gas fields in production	19
Number of producing wells	110
Present gas production capacity	2750 MMcfd
Avg. gas production rate	2633 MMcfd
Highest Production (6th May, 2015)	2785.80 MMcfd
Total recoverable (Proven + Probabale) reserve	28.69 Tcf
Cumulative Production (June,2018)	15.96 Tcf
Annual Production by NOC	385.34 Bcf (40 %)
Annual Production by IOC	575.43 Bcf (60 %)
Remaining Resurve (Proven + Probabale)	12.72 Tcf
Present Demand	3649 MMcfd
Present Deficit	1016.75 MMcfd
Number of Customer	41.80 Lakh (Appx.)

(Source: Hydrocarbon Unit, Govt of Bangladesh)

As mentioned in the table above, the remaining 2P Reserves in respective fields have been assessed as brought out in the table 2.4.2 below:

Table-2.4.2: Projection of Remaining Gas Reserves (2P) in Gas Fields

Gas Field	Total 2p Re-serve	Cumu-lative produc-tion	Projection of Gas Reserve (Remaining)									
			2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2025-26	2030-31	2035-36	2041-42
Titas	7582	4556.6	3220.8	3025.4	2829.98	2634.56	2439.14	2243.72	1462.04	484.94		
Habiganj	2787	2386.8	480.1	400.2	320.3	240.4	160.5	80.6				
kamta	50	21.1	28.9	28.9	28.9	28.9	28.9	28.9	28.9	28.9	28.9	28.9
Bakhrabad	1387	806.9	592.1	580.1	568.08	556.06	544.04	532.02	483.94	423.84	363.74	291.62
Narshingdi	345	195	160	150	139.98	129.96	119.94	109.92	69.84	19.74		
Meghna	101	66.7	38.9	34.3	29.68	25.06	20.44	15.82	0	0		
Feni	130	63	67	67	67	67	67	67	67	67		
Kailas Tila	2880	715	2188	2165	2142.04	2119.08	2096.12	2073.16	1981.32	1866.52	1751.72	1613.96
Sylhet	408	213.5	196.3	194.5	192.71	190.92	189.13	187.34	180.18	171.23	162.28	151.54
Rashidpur	3134	618.1	2535.4	2515.9	2496.39	2476.88	2457.37	2437.86	2359.82	2262.27	2164.72	2047.66
Chattak	474	25.8	448.2	448.2	448.2	448.2	448.2	448.2	448.2	448.2	448.2	448.2
Beani Bazar	137	93.6	46.9	43.4	39.9	36.4	32.9	29.4	15.4	0		
Shahbazpur	261	47.5	228.8	213.5	198.24	182.98	167.72	152.46	91.42	15.12		
Semutang	318	12.9	305.6	305.1	304.64	304.18	303.72	303.26	301.42	299.12	296.82	294.06
Fenchuganj	329	156.1	177.6	172.9	168.2	163.5	158.8	154.1	135.3	111.8	88.3	60.1
Saldanadi	275	90.3	185.7	184.7	183.64	182.58	181.52	180.46	176.22	170.92	165.62	159.26
Sundalpur	50.2	10.7	40.4	39.5	38.56	37.62	36.68	35.74	31.98	27.28	22.58	16.94
Srikail	161	75.1	98.9	85.9	72.97	60.04	47.11	34.18	0			
Jalalabad	1346	1233.3	42.8	112.7	20.61	0	0		0			
Moulavi Bazar	494	317.3	189.1	176.7	164.36	152.02	139.68	127.34	77.98	16.28		
Bibiyana	4532	3357.7	1611.7	1174.3	736.97	299.64	0		0			
Bangura	621	409.4	245.2	211.6	177.93	144.26	110.59	76.92	0			
Sangu	771	489.5	281.5	281.5	281.5	281.5	281.5	281.5	281.5	281.5	281.5	281.5
Begumganj	33	0.9	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
Rupganj	33.6	0.7	33.2	32.9	32.65	32.4	32.15	31.9	30.9	29.65	28.4	26.9
Kutubdia	46	0	46	46	46	46	46	46	46	46	46	46
Total	28685.8	15963.5	13521.2	12722.3	11761.53	10872.24	10141.25	9709.9	8301.46	6802.41	5880.88	5498.74
			Already consumed		will be produced and depleted at the current rate of Production							

(Source: Hydrocarbon Unit, Govt of Bangladesh)

As mentioned earlier, in 2012, Bangladesh was successful in getting the dispute resolved in its favour by the International Tribunal for the Laws of Seas (ITLOS) and thereafter launched another round for Off-Shore PSCs with new block boundaries. This round saw considerable interest and PSCs were signed for three Shallow Off-shore blocks, for two blocks with a consortium of ONGC Videsh Ltd (OVL), Oil India Ltd (OIL), & BAPEX, and another block with consortium of Kris, Santos & BAPEX. A PSC for a Deep Off-shore block was signed with POSCO International (S Korea). Drilling of four Off-shore wells is mandatory in the exploration of each of these blocks and the timelines have been extended till 2021.

The Off-shore blocks take a minimum of 8 to 10 years to commence production if the discoveries are found commercially viable. The delay in launching the off-shore blocks for E&P has delayed the plan for exploitation of new gas fields and discoveries.

2.4.2 Unconventional Gas

CBM: To explore the possibility of CBM production from the coal-bearing seams, a feasibility study was carried out at the Jamalganj Coal Fields which has estimated reserves of about 5.45 Billion MT of coal. But the findings did not indicate appreciable CBM quantities, and, its commercial production was not been found to be feasible.

Shale Gas: After studying feasibility, Bangladesh has for the time being deferred any investments in Shale Gas exploration and production.

2.4.3 Natural Gas Production

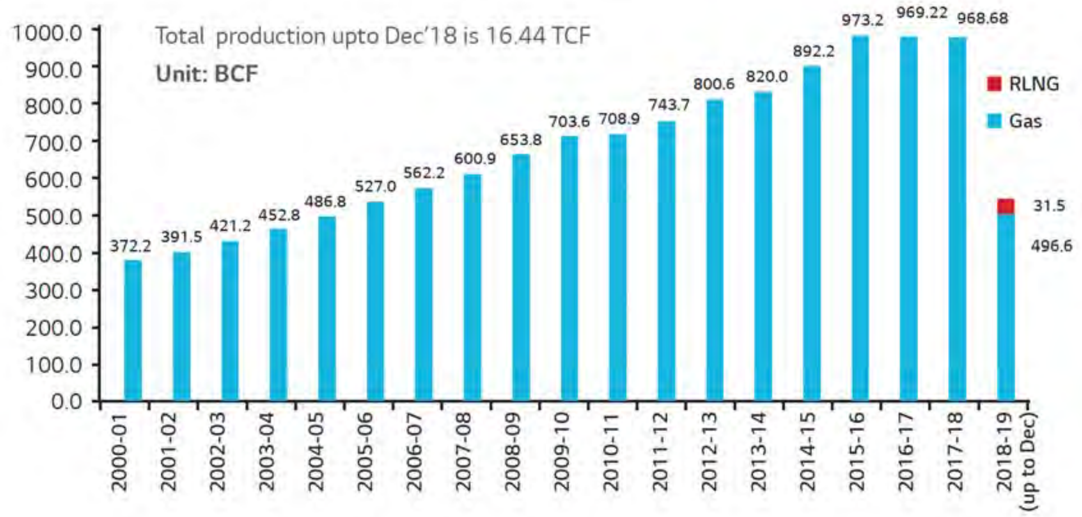
A) Domestic Gas Production: Out of total 27 gas fields discovered so far, about 21 gas fields are still producing gas. The IOCs contribute about 60% of the existing gas production and the NOCs contribute the remaining 40%. Over 90% of gas is produced from the five key gas fields, i.e., Bibiyana, Titas, Jalalabad, Habibganj and Bakhrabad, as illustrated in the map of producing fields:

Fig 2.4.1: Geographic illustration of Producing Gas Fields

(Source: Petrobangla , GSMP 2017)

The domestic gas production in 2000 was only 372 BCF (about 30 MMSCMD), and peaked in 2016-17 with about 973 bcf (75 mcmd). The production has started declining since then., as can be seen in the figure 2.4.2 below:

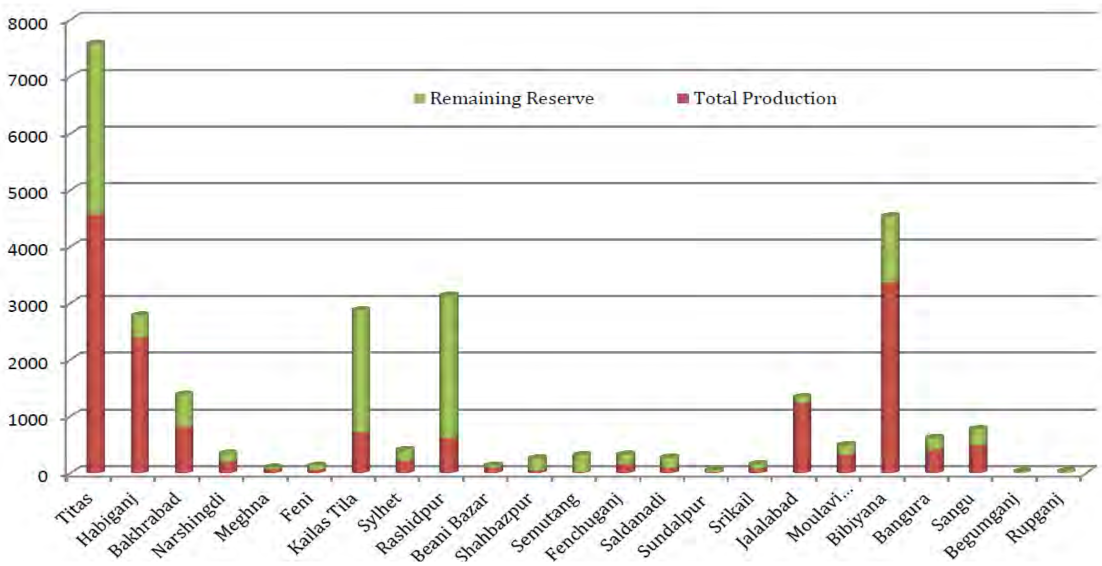
Fig 2.4.2: Year-wise gas production from 2000-01 to 2018-19 (upto Dec)



(Source: Petrobangla AR 2018-19)

The depletion of the key gas fields like Bibiyana, Titas, Jalalabad, Habibganj and Bakhrabad has been 60% to 90% as can be seen in the figure 2.4.3 below:

Fig 2.4.3: Produced and Remaining Reserves (2P) in 2017



(Source: Hydrocarbon Unit, Govt of Bangladesh)

B) LNG Supplies

The delay in launching the off-shore blocks for E&P was due to the maritime dispute with Myanmar. India delayed the plan for exploitation of new gas fields and discoveries. In 2016, to bridge the anticipated gap in demand-supply, Bangladesh signed two separate agreements with Excelerate Energy Bangladesh Ltd (EEBL) and Summit LNG Terminal Company Pvt Ltd for two FSRU, each to supply 500 mmscfd of Regasified LNG. The 'Excelerate' FSRUs was commissioned in just over 2 years from the date of entering in the agreement and supplies commenced in 2018. The 'Summit' FSRU of similar capacity (500 mmscfd), was commissioned in 2019. The gas supplies from these two FSRUs have commenced and have helped to bridge the demand-supply gap.

2.4.4 Gas Allocations

Gas Allocation is being done by the Government depending on their demand and supply. Power and Fertilizers sector gets an overriding priority, followed by Domestic households, Industrial and Commercial sectors. The demand far exceeds the supply.

2.4.5 Gas Pricing

Considering the impact on growth and the socio political implications, the gas tariffs in Bangladesh have been tightly regulated by the Government. After its formation in 2004, the BERC the gas tariffs are reviewed and revised by BERC.

The elements considered for build of gas tariffs haves been illustrated in the table 2.4.3 below. As per the methodology, the contributions to 'Energy Security Fund', 'Price Deficit fund margin', 'Support for shortfall' and 'Govt taxes' are the elements that vary across the sectors of consumption.

Table-2.4.3: Build up of the Gas Tariffs for different sectors (in USD/Mcf)

Sector	End User Price	Govt Tax	Price Deficit Fund Margin	Bapex Margin	Deficit Wellhead Margin for BAPEX	Wellhead Margin	Support for shortfall	Transm Margin	Distrib Margin	Gas Dev. Fund	Energy Security Fund
Power	1.38	0.67	0.14	0.02	0.02	0.10	0.15	0.07	0.12	0.04	0.05
Fertilizer	1.19	0.62	0.12	0.00	0.02	0.10	0.06	0.07	0.12	0.07	0.02
CNG	13.91	6.46	2.65	0.05	0.09	0.13	2.17	0.07	0.07	1.37	0.87
Capt. Power	4.21	2.00	0.20	0.02	0.02	0.10	0.55	0.07	0.07	0.09	1.09
Industry	3.40	1.61	0.33	0.02	0.02	0.10	0.44	0.07	0.11	0.12	0.57
Tea Garden	3.25	1.54	0.33	0.02	0.02	0.10	0.42	0.07	0.11	0.12	0.48
Commercial	7.46	2.72	0.58	0.02	0.02	0.10	2.47	0.07	0.11	0.24	1.09
Domestic	4.90	1.67	0.31	0.02	0.02	0.10	1.83	0.07	0.11	0.12	0.65

(Source: Hydrocarbon Unit, EMRD)

It can be seen from above that the gas Tariffs vary across the sectors, i.e., Power, Fertilizers, Industrial, Captive Power, Commercial, Household and CNG. However, , Bangladesh has historically enjoyed lowest gas tariffs as compared to its neighbours as can be seen in the Table below:

QGC LNG Plant - Courtesy of Shell

Table-2.4.4: Gas Tariffs in Bangladesh

(As in December, 2018) Taka/MCF

Effective From	Power	Fertilizer	Industry	Commer-cial	Tea estate	Cap. Power	CNG feed gas	Brick field (season-al)	Domestic		
									Metered	Single Burner	Double Burner
29.07.1968	1.20	1.20	2.52	6.00	-	-	-	-	6.00	6.00	10.00
28.06.1969	1.60	1.60	2.92	6.40	-	-	-	-	6.40	6.30	10.50
19.06.1974	3.72	3.72	7.20	12.00	-	-	-	-	12.00	15.00	28.00
01.12.1977	5.00	5.00	9.00	13.00	-	-	-	-	13.00	16.00	30.00
02.06.1979	6.25	6.25	16.00	17.00	-	-	-	-	16.00	20.00	36.00
07.06.1980	7.75	7.75	18.00	19.00	-	-	-	-	18.00	22.00	40.00
07.06.1981	9.30	9.30	27.75	28.00	-	-	-	-	20.00	25.00	45.00
01.07.1982	10.50	10.50	31.00	31.00	-	-	-	-	27.00	35.00	65.00
30.06.1983	11.50	11.50	36.00	36.00	-	-	-	-	34.00	45.00	80.00
27.06.1984	13.05	13.05	36.00	45.20	-	-	-	51.00	34.00	45.00	80.00
30.06.1985	15.66	15.66	43.20	54.24	-	-	-	61.20	40.80	60.00	100.00
28.06.1986	19.09	19.09	52.14	65.39	-	-	-	78.30	44.88	66.00	110.00
18.06.1987	24.82	24.82	52.14	85.00	72.30	-	-	78.30	56.10	80.00	130.00
01.07.1988	28.54	28.54	59.96	97.75	83.15	-	-	90.05	56.10	92.00	150.00
01.07.1989	33.00	28.54	70.00	110.00	83.15	-	-	-	65.00	100.00	170.00
01.07.1990	37.95	32.82	80.42	126.50	95.62	-	-	-	74.75	115.00	195.00
01.07.1991	39.08	33.98	85.23	134.22	100.62	-	-	106.19	74.75	115.00	195.00
01.05.1992	43.05	37.39	93.74	134.22	110.16	-	43.05	116.67	82.12	126.00	215.00
01.03.1994	47.57	41.34	103.07	147.53	113.26	-	-	128.28	82.12	160.00	250.00
01.12.1998	54.65	47.57	118.93	169.90	130.26	86.37	-	147.25	94.86	185.00	290.00
01.09.2000	62.86	54.65	136.77	195.39	149.80	99.11	-	169.33	109.02	210.00	330.00
01.01.2002	65.98	57.48	143.57	205.30	157.16	104.21	-	177.83	114.40	275.00	350.00
01.09.2002	70.00	60.00	140.00	220.00	140.00	100.00	-	220.00	120.00	325.00	375.00
15.02.2003	-	-	-	-	-	-	70.00	-	-	-	-
01.07.2004	72.45	62.15	145.20	228.50	145.20	-	-	228.50	126.10	340.00	390.00
01.09.2004	-	-	-	-	-	103.50	-	-	-	-	-
01.01.2005	73.91	63.41	148.13	233.12	148.13	105.59	-	233.00	130.00	350.00	400.00
25.04.2008	-	-	-	-	-	-	282.30	-	-	-	-
01.08.2009	79.82	72.92	165.91	268.09	165.91	118.26	-	-	146.25	400.00	450.00
12.05.2011	-	-	-	-	-	-	509.70	-	-	-	-
19.09.2011	-	-	-	-	-	-	651.29	-	-	-	-
01.09.2015	-	-	190.86	321.68	182.64	236.73	764.55	-	198.22	600.00	650.00
01.03.2017	84.67	74.76	205.01	402.10	196.24	254.29	849.50	-	257.68	750.00	800.00
01.06.2017	89.48	76.74	219.74	482.52	210.11	272.41	906.14	-	317.15	900.00	950.00
01.08.2017	89.48	76.74	219.74	482.52	210.11	272.41	906.14	-	257.68	750.00	800.00
18.09.2018	89.48	76.74	219.74	482.52	210.11	272.41	906.14	-	257.68	750.00	800.00

(Source Petrobangla AR 2018-19)

(100 Taka/MCF is about 1.16 $/mmbtu at 1 USD = 85 Takas)

In 2018, Bangladesh commenced import of RLNG and in 2019, BERC after considering the increase in the costs borne by Petrobangla, increased the tariffs by nearly 32% over the previous tariffs declared in 2017. The comparision of the tariffs in 2017 & 20019 with prices in BD Taka / Cubic metres and equivalent in USD/MMBTU are produced in the table 2.4.5 below:

Table-2.4.5: Gas Tariffs in 2017 & 2019 for different sectors in Taka/cm & USD/MMBTU

Gas Prices in Bangladesh						
Sector	Prices in BDT/Cu Metre			Prices in $/mmbtu	Increase	
	Share in %	2017	2019	2017	2019	(in %)
Power	40	3.16	4.45	1.07	1.51	41
Captive Power	16	9.62	13.85	3.27	4.71	44
Fertilizers	5	2.71	4.45	0.92	1.51	64
Industrial	17	7.76	10.7	2.64	3.64	38
Commercial	1	17.04	23	5.8	7.82	35
CNG	5	40	43	13.61	14.63	7
Domestic	16	9.1	12.6	3.1	4.29	38

The tariff revisions are sensitive to the socio-political environment and the Government and BERC have adopted a very cautious approach in the revisions of tariffs. As observed in table … above, Even after the 32% increase, tariffs in Power, Fertilizers, Household and Industrial sectors are two to three times less than India.

2.4.6: Subsidy

Bangladesh ranks amongst the countries with lowest gas tariffs. As per ADB, its tariffs are comparable with the six countries of Gulf Cooperation Council (GCC) which are large producers of gas. The tariff policy indicates that the consumers / some sectors are cross-subsidised to take care of income disparities Even after the revision, its prices are just about 1.5 $/mmbtu for Power and Fertilizers. As per the Profit and Loss Statement in Annual Report of Petrobangla (AR 2018), the 'Loss' for 2018 was 20.312 Billion Taka and Cumulative losses are 107 Billion Taka.

In its report on Energy Policy Options for Sustainable Development in Bangladesh (2013) Asian Development Bank (ADB) reviewed the gas tariffs and compared it with the neighbouring countries like India, Pakistan, Malaysia etc. It reviewed the economic value of gas in different sectors and observed that low tariffs have undermined energy security and has discouraged efficient use of gas. It observed that the impact of negative growth in economy could be countered by improving the efficiency in its usage. It was supportive for the low tariffs for Fertilizers, but not for other sectors like CNG, Household and Power based on the 'Willingness to Pay' (WTP) factor. For the power sector, it advocated for replacing gas with coal-based capacity addition. The increase in the gas tariffs would neutralise the perceived negative growth and fetch in enough surpluses for the Government to plough it back in different sectors of economy and in exploration of hydrocarbons.

2.5 Gas Infrastructure and Supplies

2.5.1 Key Pipelines

Bangladesh has a very dense network of tributaries, rivulets and the delta regions of the Brahmputra and the Ganges river spread across its geography. The river systems are also subject to seasonal floods. Their key gas producing fields are in the eastern folds, located in the Eastern and North-eastern part of the country, as shown in fig 2.5.1. Transporting the gas to the consumers in rest of the country require laying of pipelines and crossing the wide span of rivers Brahmputra and Padma as also crossing of streams, rivulets and rivers. Seasonal floods and rise of levels during the tropical cyclones and storms add to difficulties in construction of pipelines and crossings / bridges. Besides, being an agriculture oriented economy with a dense population, acquiring land and 'right of way' has remained a major constraint in laying of pipelines. In spite of these limitations, Bangldesh has developed a healthy network of pipelines and compressors across the geography. For its geographical area that is less than 5% the area of India, its network of trunk pipelines (along with lateral spur pipelines) is about half that of India. Its total network of transmission and distribution pipelines is about 24, 239 kms and comprises of the following:

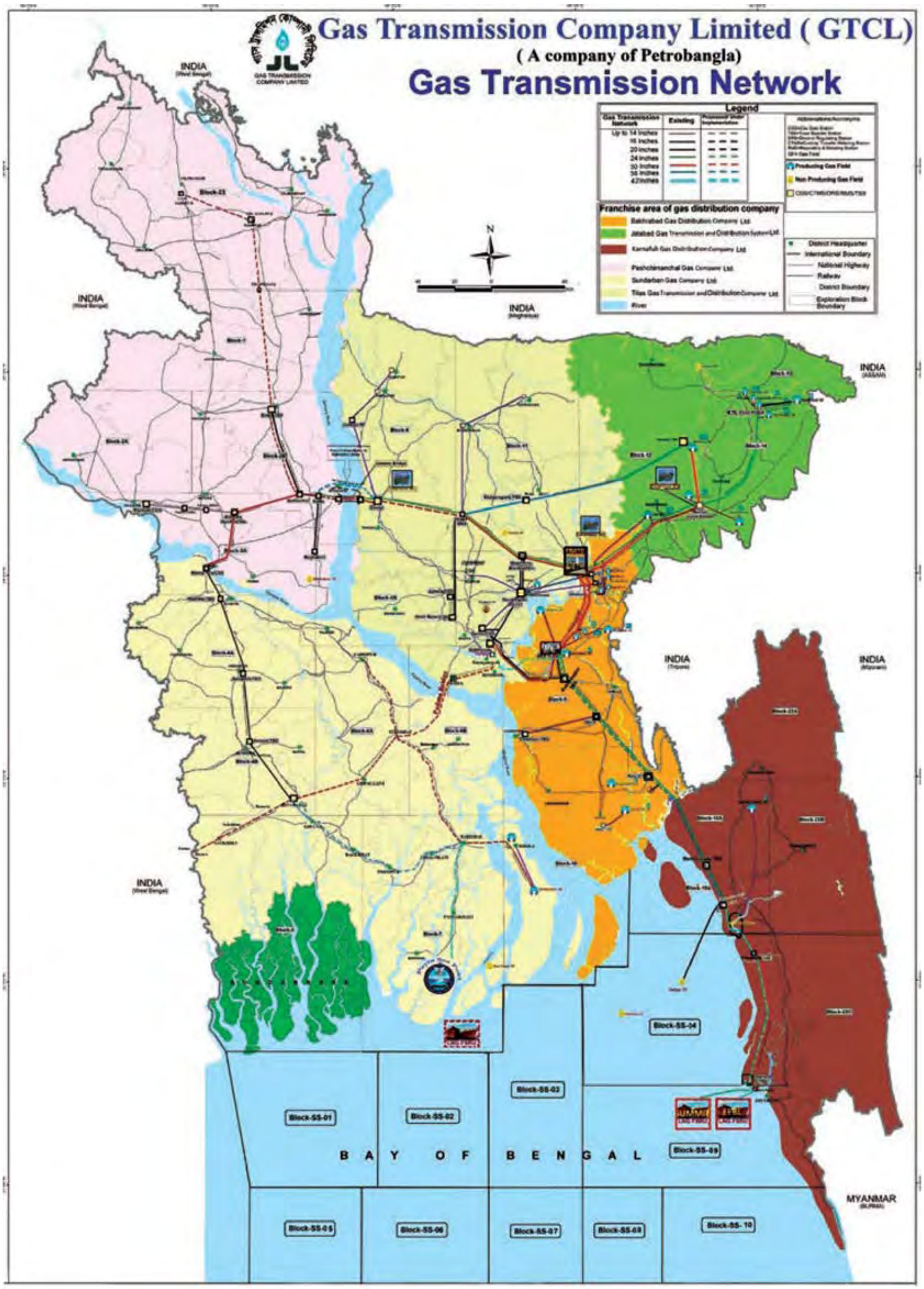
- 2,872 kms of Trunk (Transmission) Pipelines
- 2,381 kms of Distribution lines
- 235 kms of Lateral Pipelines
- 16,706 kms of Feeder Pipelines
- 2,045 kms of Customer Financed Pipelines

The entire pipeline network including the compressor stations along with Supervisory Control and Data Acquisition system (SCADA) is implemented and operated by Gas Transmission Company Ltd (GTCL), a fully owned subsidiary of Petrobangla. The gas transmission network of GTCL with all key pipelines is illustrated below at Fig 2.5.1

The decline in the production of its existing gas fields and the decision to install RLNG plants and FSRUs in Moheshkhali area of Cox Bazaar in Southern-East tip has raised pipeline logistic constraints in meeting demand. Further, the growth of demand of consumers of TGTDCL, PGCL & SGCL has further surmounted the necessity for remodelling the flow patterns and has posed new challenges. To overcome these, Petrobangla/GTCL has launched a programme for laying new trunk pipelines to evacuate and transport gas to rest of the country. The key pipelines under implementation are:

- Moheshkhali Zero point to Dholghat Para - 42” X 7 kms
- Mohesshkhali to Anowara - 42” X 79 kms parallel pipeline
- Dhanua-Elanga and BangabandhuBridge West Bank- Nalka – 30” X 67.2 kms
- Padma river crossing 30” X 6.15 kms
- Bakhrabad – Feni- Chattogram - 36” X 181 kms
- Bogura – Rangpur – Saidpur: 30” X 150 kms

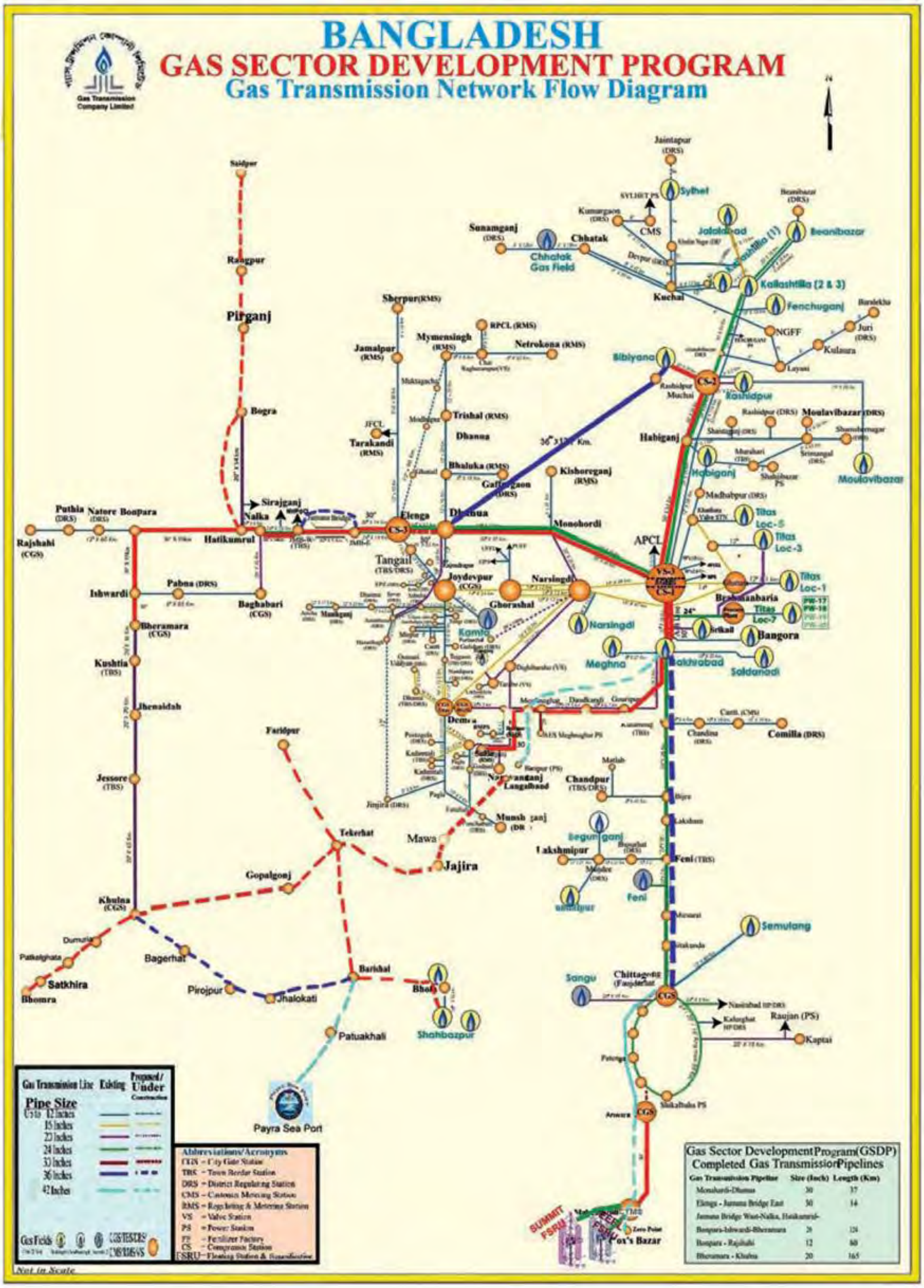
Fig2.5.1.Map of Trunk Pipelines of GTCL (Existing pipelines - firm, Under Construction – dotted)



(Source Petrobangla AR 2018-19)

The pipelines under construction as well as the existing pipelines alongwith the gas fields, FSRUs and Compressor stations are illustrated in the figure 2.5.2 below:

Fig 2.5.2: Key existing and under construction pipelines alongwith Gas Fields, FSRUs & Compressor Stations. Existing pipelines - firm, Under Construction – dotted



(Source: Petrobangla AR 2018-19)

2.5.2 RLNG / FSRU Facilities

Rupantarita Prakitik Gas Company Ltd (RPGCL), a company operating under Petrobangla, looks after promoting the CNG business and the installations for refining of Condensate and Natural Gas Liquid (NGL). The RPGCL is also entrusted to oversee the LNG receiving terminals / FSRUs by Petrobangla.

A) FSRU: As land-based LNG receiving and regasification terminals take considerable time for award and project execution, Bangladesh has gone ahead with hiring two FSRUs on 'Build-Own-Operate-Transfer' (BOOT) basis for 15-year term. The FSRU come up in two years after award of contract. At present, two FSRUs, 'Excellent' and 'Summit' are in operation, in Cox's Bazar, near Moheshkhali with a capacity of 500 mcfd each. The details are as follows:

Table-2.5.1: Details of Existing FSRU in Operation in Bangladesh

Name of Terminal	MLNG	SLNG
Name of FSRU	Excellence	Summit
Location	Near Moheshkhali Island	Near Moheshkhali Island
Dimensions	Length 277 m, Width 44m, Draft 12.5	Length 277 m, Width 44m, Draft 12.5
Regasification Capacity	500 mcfd	500 mcfd
Storage Capacity	138,000 Cubic Metres	138,000 Cubic Metres
Contract Mode	BOOT (Build Own Operate and Transfer)	BOOT (Build Own Operate and Transfer)
Contract Term	15 Years from COD (2018-33)	15 Years from COD (2018-33)
Date of signing of Contract	18th July 2016	20th April 2017
Commercial Start Date (COD)	19th Aug 2018	30th April 2018

(Source Petrobangla)

The following arrangements on G-to-G basis between the governments of Bangladesh with Governments of Qatar and Oman have been made for sourcing the LNG requirement:

- On 25.9.2017, an agreement for Delivery Ex-Ship (DES) basis has been signed with Ras Laffan (Qatar) for supply of 1.8 MTPA for 5 years and 2.5 MTPA for the next 10 years.
- On 6.5.2018, a Sale & Purchase Agreement (SPA) has been signed with Oman Trading International for upto 1.5 MTPA LNG.

Further, 30 suppliers across the globe have been short listed to meet any exigency requirement from Spot LNG Markets.

B) LNG Receiving Terminal: A MoU for conducting a feasibility report for a 7.5 MTPA land-based RLNG terminal (near Moheshkhali in Cox's Bazar) was signed on 20.11.2016 with a consortium of China's Huanqui Contracing and Engineering Corporation (HQC) and China CAMC Engineering Co Ltd (CAMC). The agreement for preparing the FR was signed on 1.8.2017, and the consortium submitted its report on 31.1.2018. The consortium has submitted its Technical and Final Proposal and a decision is yet to be taken. The terminal will take 4 years from the date of award.

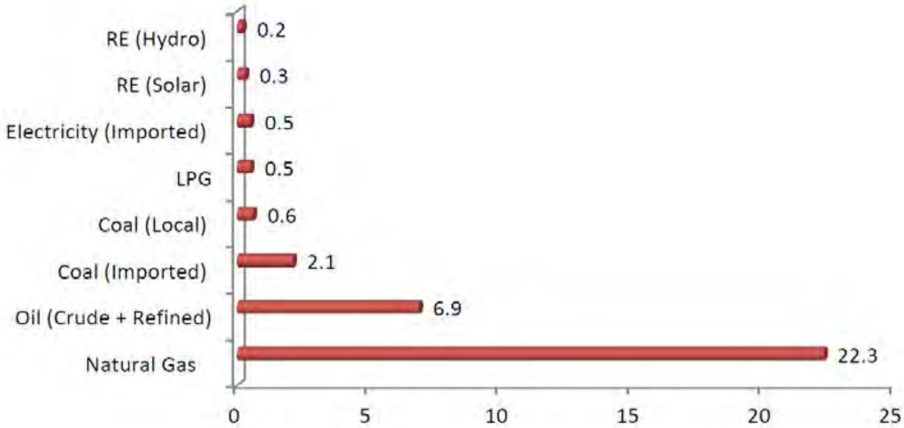
Further, an EOI was invited for a land based RLNG terminal of similar capacity (1000 mcfd) on 'BOOT' basis and 5 bids have been shortlisted. A final decision is yet to be taken.

In addition, another Land-based RLNG terminal at Matarbari is also envisaged and 12 companies have expressed interest against the EOI floated in Jan 2019. This terminal shall come up on 'BOOT' basis and transfer shall be after 20 years of Operation.

2.5.3 Gas Supplies and Sector-wise gas consumption

Gas plays an important role in the Primary as well as Commercial energy consumption in Bangladesh. As per the Energy Scenario Report 2017-18 by Hydrocarbon Unit of EMRD, Govt of Bangladesh, the share of Gas in Primary Energy Consumption of 47 MTOE was about 48%. In terms of the commercial energy consumption, its share is 22.3 MTOE out of 33.4 MTOE, which is about 66% of the commercial primary energy consumption as in the figure below:

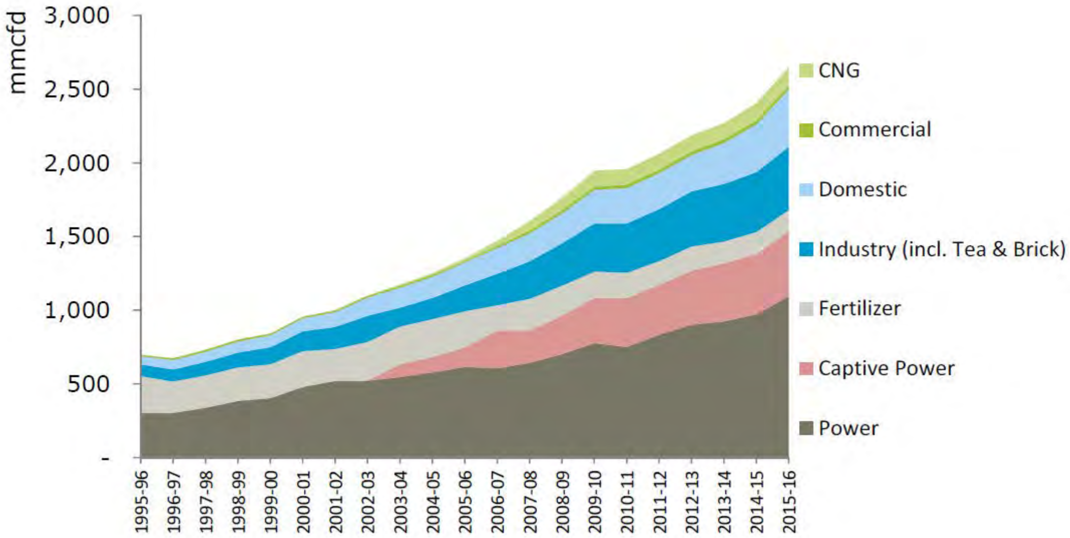
Fig 2.5.3: Sources of Commercial Energy consumption of 33.4 MTOE in 2017-18



(Source Hydrocarbon Unit, EMRD)

Power and Fertilizers, followed by Industries and Domestic households, had the priority in allocation and consumption. The historical consumption has been mapped in the figure below:

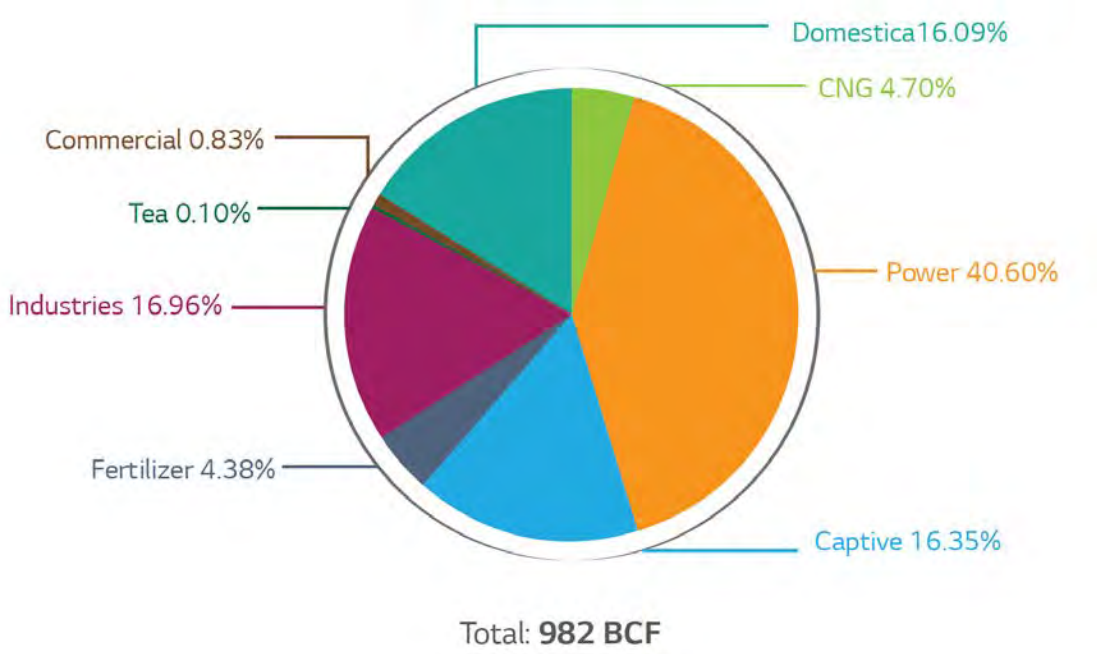
Fig 2.5.4: Historical sector-wise gas consumption in Bangladesh



(Source – Petrobangla AR)

The Power Sector (including Captive Power) consumed about 56-60% of the gas consumption. The Industries and Domestic households consume 16% each followed by Fertilizers (4.38%) and Domestic (4%) as shown in Fig 2.55

Fig 2.5.5: Sector-wise share in gas consumption in 2018



(Petrobangla, Annual Report 2018-19)

The demand exceeds the supply.

2.6 Projections of Gas Supply and Demand

2.6.1: Projections of Domestic Gas production

A) Existing status of Gas Reserves & Production

The gas production in Bangladesh peaked in 2016-17 and production is on a decline as the reserves are depleting. As per the Energy Scenario 207-18 by the Hydrocarbon Unit, by 2040-41 the 2P reserves are likely to deplete to about 5.5 tcf and the production to just 64 bcf as in the Fig 2.6.1 & 2.6.2.

Fig 2.6.1: Remaining 2P Reserves of Gas (in BCF)

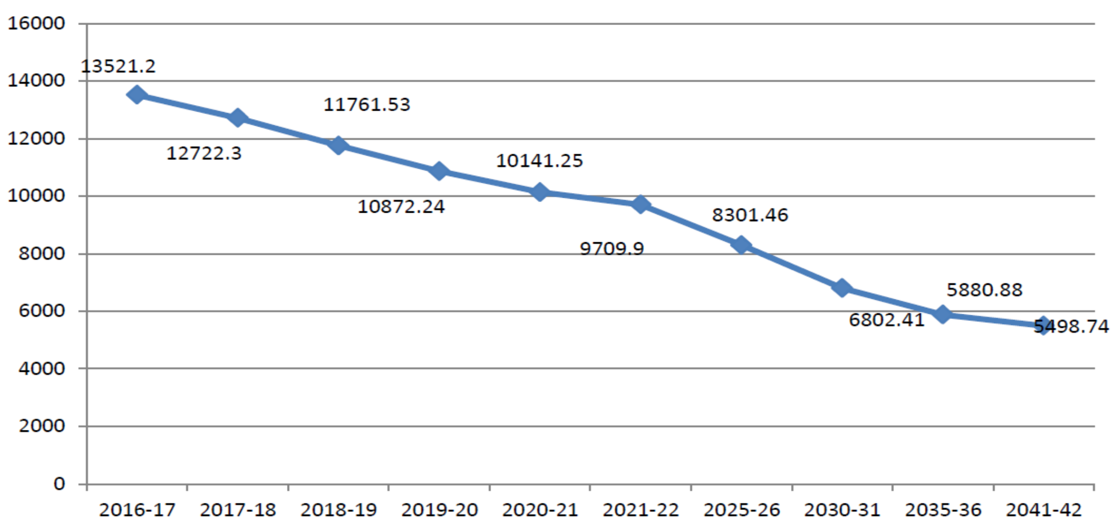
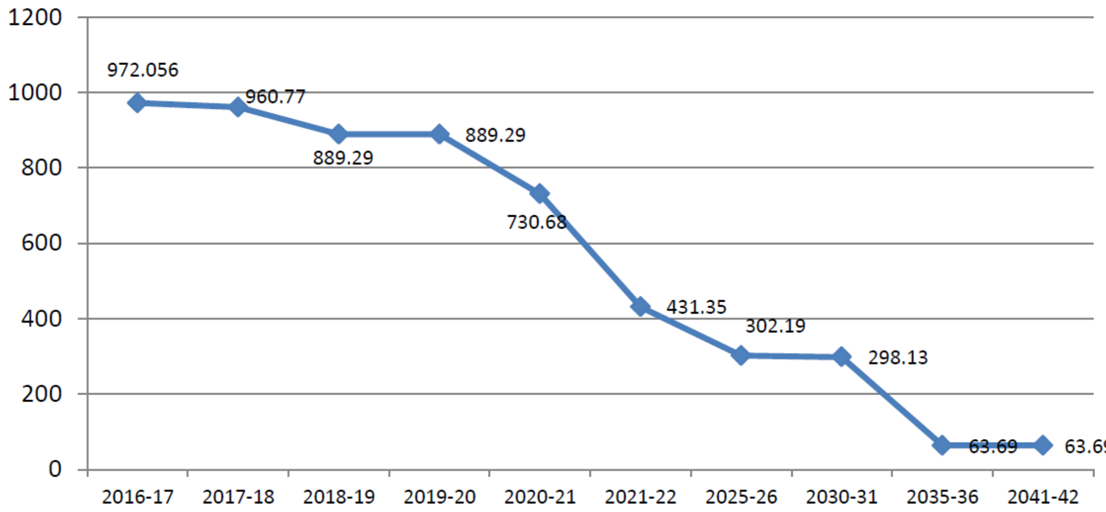


Fig: 2.6.2 Projection of Gas Production (in BCF)



(Source: Energy Scenario 2017-18 by Hydrocarbon Unit, Energy & Mineral Resource Division, Govt of Bangladesh)

As mentioned above at 2.4.1, Bangladesh has estimated sedimentary basins spread across 207,000 sq kms within its territories. Further, the majority area has not been explored or is underexplored. This includes about 119,000 sq kms of unexplored area in the shallow and deep offshore maritime region. Myanmar has already reaped rich dividends in hydrocarbon production from their offshore blocks bordering Bangladesh. The exploration of this majority area of its sedimentary basin are a key to find new discoveries and arrest its declining reserves In addition to the programme of taking up exploration between 2016 to 2021, .Petrobangla has launched two ambitious programs. The first is to revise its PSCs for the Onshore and Offshore exploration & production. The second program is to take up 2D Non-exclusive Multi-client Seismic Survey. The objective is to acquire comprehensive geological data of its Offshore areas which will aid in assessment of its basins/blocks and attract healthy participation from the prospective bidders in the next round of licencing.

The Off-shore blocks take a minimum of 8 to 10 years to commence production if the discoveries are appraised and found commercially viable. The delay in launching the off-shore blocks for E&P has delayed the plan for exploitation of new gas fields and discoveries.

Gas Sector Master Plan 2017 (GSMP 2017): Ministry of Power, Energy & Mineral Resources, Govt of Bangladesh have consulted Ramboll for drafting the Gas Sector Master Plan 2017 (GSMP 2017). The consultants were provided the available inputs including the USGS-Petrobangla studies in 2001, the previous GSMP-2006 (Woodmackenzie), a detailed the report by Gustavson in 2011, available exploratory data etc. Based on these inputs, the consultants have drafted a GSMP 2017. It has forecasted the short to mid-term projections as well as Lon g-term projections of indigeneous gas production. It has also reviewed the Power Sector Master Plan (PSMP-2016) prepared by JICA a year or so earlier and has updated the gas supply and demand projections. It has assumed Proven and Probable reserves for short-term planning say upto 5-10 years, and the Possible and additional 'Yet-to-Find' (YTF) reserves as useful for strategic long-term plan.

For the Short to Mid-term projections, Ramboll has relied on the historical data of exploratory success and increase in the Gas Initial in Place (GIIP) reserves by about 500 bcf per annum. The consultants conclude that estimated contribution of 'Yet-to-Find' (YTF) as 6.4 tcf, (2.6 tcf from new onshore fields and 2.1 & 1.7 tcf respectively from shallow offshore and deep offshore fields. The consultants agree with these YTF estimates based on the past history for medium term.

For Long-term projections, the consultants have concluded that large geographical areas remain unexplored. It believes that there is significant potential for indigenous gas production and conclude that a well planned and structured exploration strategy can increase the average GIIP growth rate well above the 500 bcf per year. They have also recommended that the P90 Risked Conventional Resource of YTF as summarised from the assessment by Gustavson (2011) which is about 34,419 bcf (or about 34 tcf) .

While the consultants have reviewed the Thin Bed and Unconventional gas reserves as appearing in the input reports, however, for the purpose of planning and taking into account their assessment of the business scenario, they have not considered these reserves for production in future.

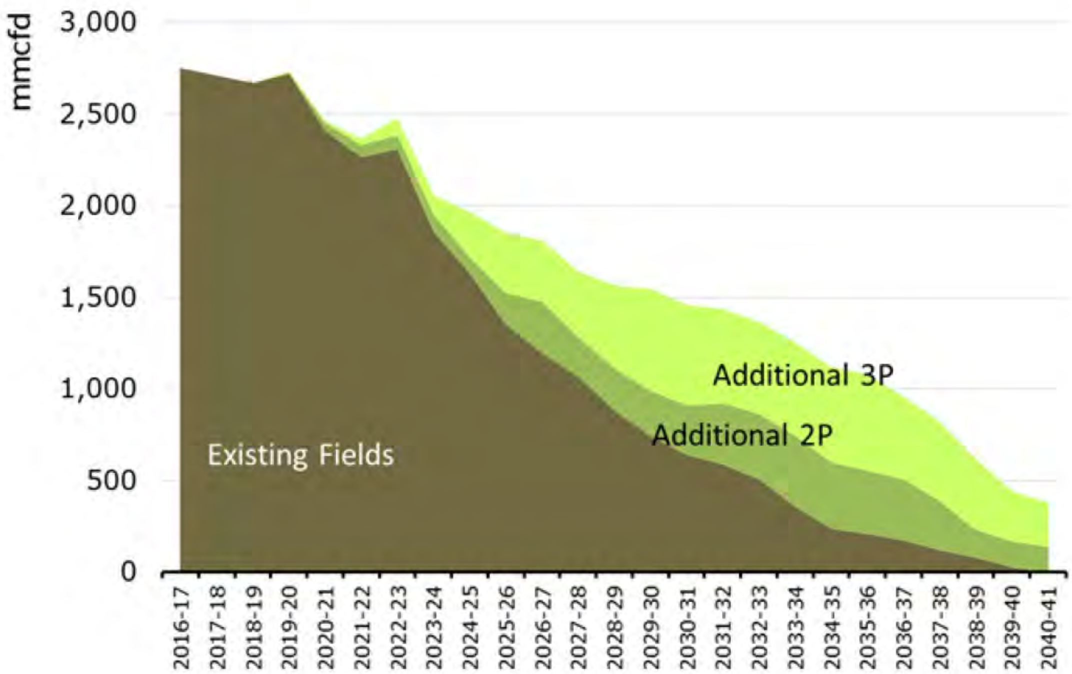
2.6.2: Domestic Gas production scenarios

As analysed in the GSMP 2017, three gas production profiles, and accordingly three supply scenarios have been drawn depending upon the state of exploration and certainty of domestic production. These are

Supply Scenario 1: Proved, Probable and Possible Scenario (3P)

Total GIIP reserves of the existing gas fields under production were 35.85 tcf, out of which 24.296 are proven. About 13.5 tcf has already been produced and remaining 10.8 tcf is available for future production. By utilising the latest 3D Seismic & Imaging data of the existing gas fields (including those where production has been suspended), and appropriate technologies, the recovery factors can be improved upon. It is anticipated that the existing gas fields can provide 1.84 tcf of Additional 2P and 4.93 tcf of Additional 3P reserves. This Scenario 1 projects the expected production from existing fields / workovers as in the Figure below:

Fig 2.6.3: Production Forecast from Proved, Probable and Possible reserves
(Source: Petrobangla, GSMP)

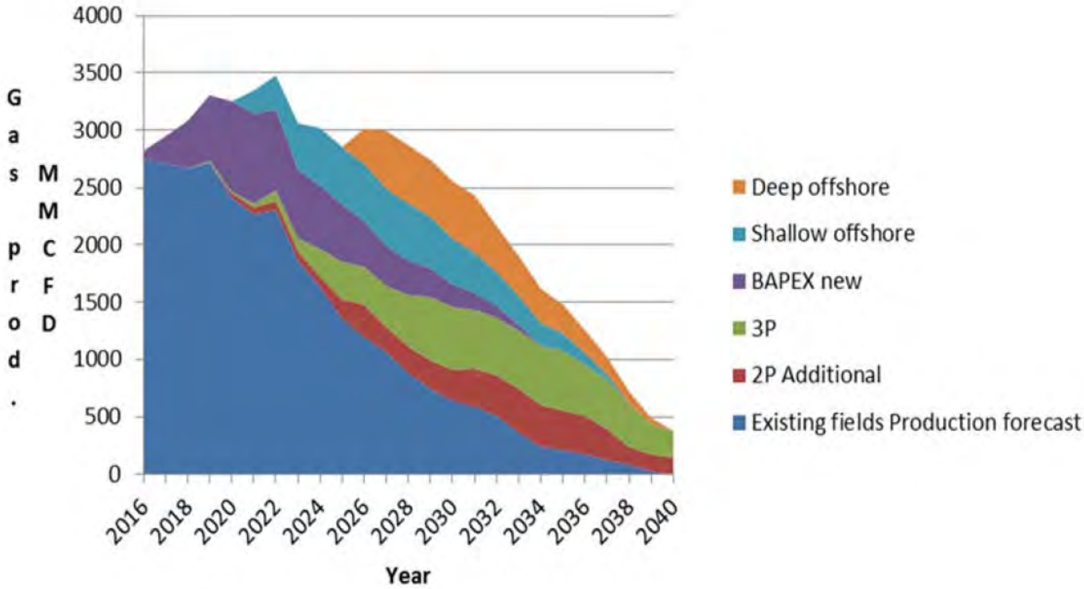


Supply Scenario-2: Proven, Probable, Possible and 6.4 tcf of YTF Reserves (3P + 6.4 YTF): The report has relied on the historical data of exploratory success (leading to increase in the Gas Initial in Place (GIIP) reserves by about 500 bcf per annum), the subsequent geological data, current interpretations, exploration programs etc. It concludes that the new gas fields are likely to contribute 6.4 tcf as follows:

- 2.6 tcf from new onshore fields
- 2.1 tcf from new shallow water off-shore fields
- 1.7 from new deep water off-shore fields

The production reaches about 3500 mcfd in 2025, declines to 2500 mcfd in 2030 and then to 500 mcfd in 2041 as mapped below:

Fig 2.6.4: Proven, Probable, Possible Reserves (3P) with 6.4 tcfYTF contributions

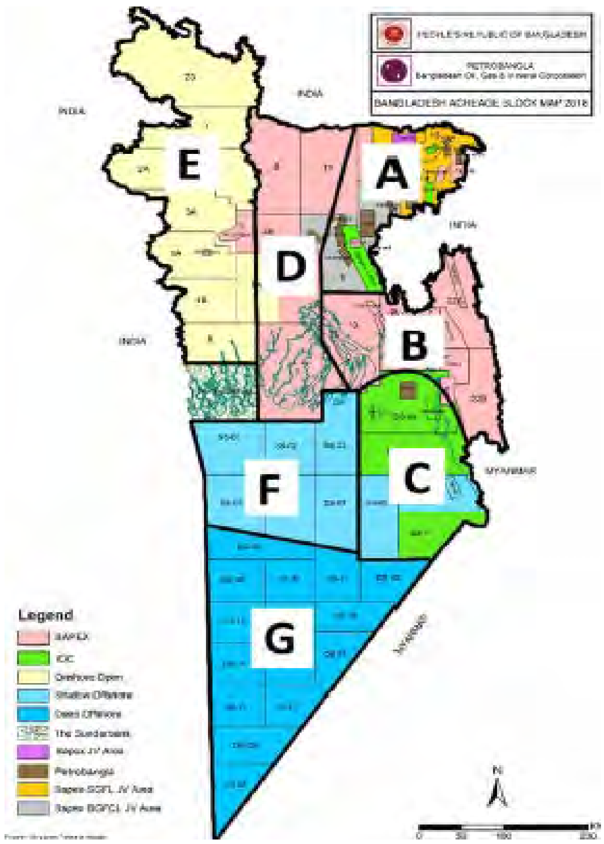


(Source: GSMP 2018)

Supply Scenario-3: High Production: Proven, Probable, Possible and YTF Reserves of 34 tcf (3P + 34 YTF)

A detailed analysis carried out in 2011 (Gustavson) indicated new undiscovered gas resource of 34.4 tcf (90% probability) to 80 tcf (10% probability). BAPEX has launched an exploratory drilling campaign and other exploration initiative 2016-21 for discoveries and development of fields. The resource base has been divided in 7 Blocks as follows:

Fig 2.6.5: The geographical areas (A to G) based on present exploration activities



(Source: Petrobangla, PSMP)

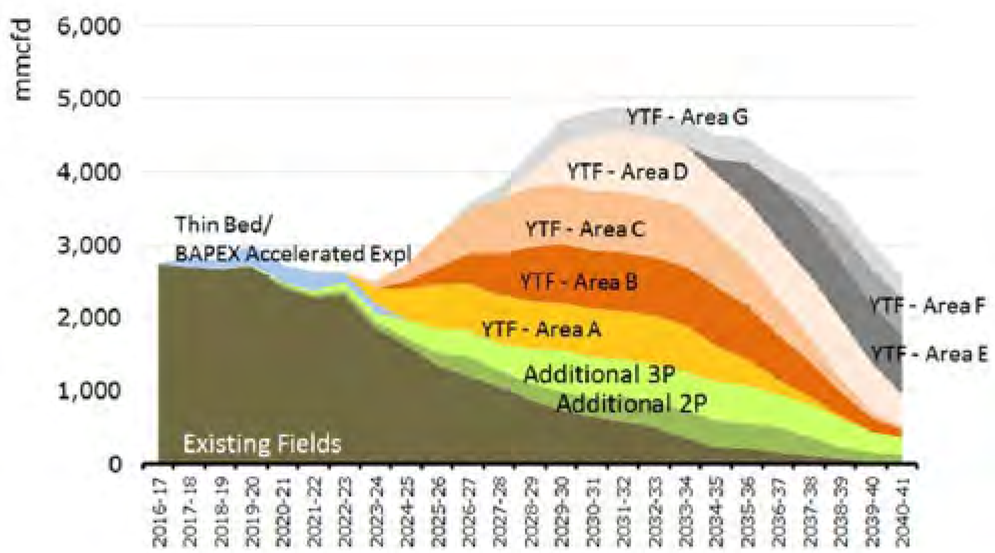
The information for area-wise exploration status (A-G), expected discoveries with probability, likely recovery factors and expected timelines has been compiled as follows:

Table-2.6.1: Overview of Yet to Find (YtF) Reserves (Source: Petrobangla GSMP 2018, Ramboll

Area	Location	Exploraton Status	Reserve (P90)	Probability of Success (in %)	Recovery Factor (in %)	Expected Production (Years from now)
A	On Shore	Proven Thin bed	1-3 tcf	30	20	5-10 Y
		Proven Reserve	3-5 tcf	33	70	5-10 Y
B	On Shore	Proven	3-5 tcf	31	70	7-12 Y
C	Shallow Offshore	Proven	4-6 tcf	31	70	10 - 20 Y
D	Onshore	Under Exp	4-6 tcf	23	70	11 - 20 Y
E	Onshore	To be explored	4-6 tcf	13	70	15 - 20 Y
F	Shallow Offshore	To be explored	2-3 tcf	13	70	15 - 20 Y
G	Deep Offshore	Under Exploration		31	70	15 - 25 Y

The GSMP has also outlined 5-year plans for Area-wise exploration and production activities for above seven areas. The gas production profile is projected to touch 3,000 mcfd in 2025, 4,750 mcfd in 2030, and then decline to 2,750 mcfd by 2040-41, as brought out in Figure 2.6.6. below

Fig 2.6.6: High Production Scenario – Proven, Probable, Possible(3P) and 34 tcf of YTF



(Source: Petrobangla GSMP 2018, Ramboll)

In view of the existing and planned exploration activities, the following two scenarios can be considered for analysing the future demand-supply gap:

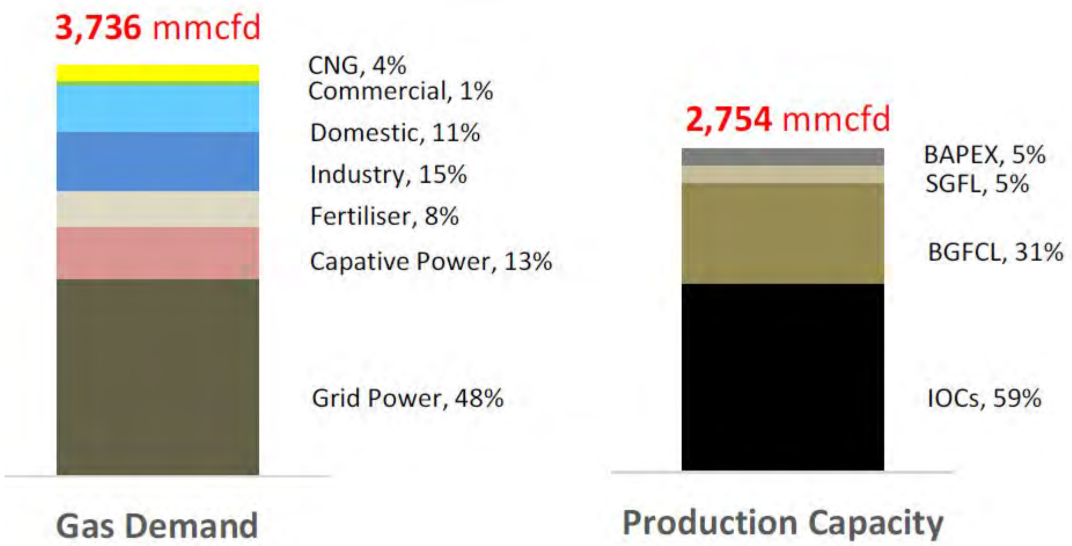
1. **Supply Scenario-2: Realistic: 3P + YTF of 6.4 tcf**
2. **Supply Scenario-3: High Production: 3P + YTF of 34 tcf**

2.6.3 Drivers for Demand

a) **Macroeconomic indicators:** The GDP growth of Bangladesh was 8.1% in 2019 and Pre-Covid GDP for 2020 was targeted as 8%. As per the World Bank, in the last decade, poverty dropped by a third with improvements in HDI, life expectancy, literacy and per capita food consumption. Its Forex reserves have grown from 10 Bn USD in 2009 to 30 Bn USD in 2019. In the last decade, it has recorded a growth of over 10% CAGR in power generation, which is also a promising sign of the surge in economic activities. The growth in GDP and exports together with a low per capita income and power consumption (375 kwhr against global average of around 2750 kwhr) are indicators of the potential for increasing its per energy consumption. It can aim to achieve at least three to four times over next decade. Bangladesh had envisioned becoming a middle income nation by 2021 and a developed nation by 2041. In the 'Rupkalpa (Vision) 2041' approved in Feb 2020 by the National Economic Council (NEC) headed by the Prime Minister, the GDP growth is targeted at 9% till 2031 and 9.9% from 2031 to 2041. The per capita annual income is targeted to reach 12,500 USD by 2041.

b) **Existing Unmet gas demand:** Many consumer-segments like CNG and Power have more appetite for gas. This is gauged by the fact that the unconstrained demand on 2016-17 was about 3,736 mcfd against the toatal gas supply of 2,754 mcfd as illustrated in GSMP:

Fig 2.6.7: Gas Demand and Supply:
(Source Petrobangla, GSMP 2017)



c) **Demand side Management for efficient utilization:** About 70% of the gas is consumed by Fertilizers (8%) and Power (Grid -48% & Captive – 13%). In 2014, the gas consumption of Urea plants in Bangladesh was 44 mcf/ton against the global benchmark of 25 mcf/ton. As per BERC, the efficiency of Bangladesh's gas based power plants was around 38%, well below the globally accepted average of 45%. There is a scope of at least 25% improvement in specific consumption, thereby sparing gas for Industry and other sectors for realizing more economic value of gas.

d) **Commitments in COP -21:** Paris Agreement: Bangladesh is vulnerable to the aftermaths of climate change and global warming. It has already begun to experience extreme temperatures, irregular rainfall, droughts & floods, tropical cyclones & tidal surges, backflow of sea water due to rising sea levels in the Bay of Bengal etc. Its Intended Nationally Determined Contributions (INDCs) as committed in Paris Agreement include:

- Unconditional reduction of GHG by 5% from BAU levels by 2030
- Conditional 15% reduction in GHG from BAU levels by 2030 in Power, Industrial and Transport sector subject to appropriate international support
- A number of further mitigation measures for reduction of GHGs

To adopt and pursue measures to combat climate change is a natural choice foe Bangladesh. It is likely that it may proceed cautiously and opt for gas-based plants in favour of coal-based plants for its capacity addition program.

e) **Slippages in planned capacity expansion from other sources/substitute (like Coal & Nuclear):** Many of the coal-based power plants under capacity addition program are facing environmental issues in implementation. It is likely that the delays or non-materialization of planned capacities from other sources may compel gas-based capacity addition.

f) **Imports from neighbouring countries:** Myanmar and India offer opportunity of importing gas. Myanmar is already exporting gas to Thailand and China. It is pursuing an intensive E&P program that may yield surplus gas. India, though short in indigenous gas production, is developing a number of FSRU / LNG Receiving terminals along with pipeline network. Some of these upcoming pipelines would run very close to Bangladesh and offer opportunity for imports. The federal governments of both countries have approved the same in principle. Bangladesh is already importing power from India.

2.6.4 Sector-wise Demand Projections

As discussed in Paragraphabove, the key gas consumers are:

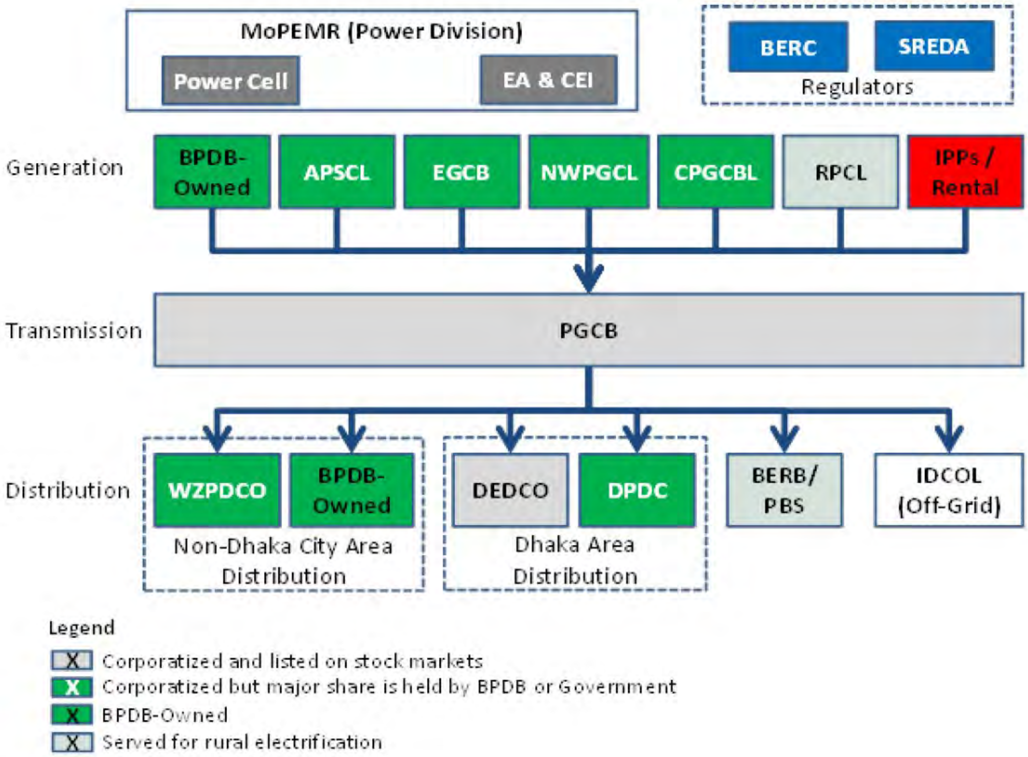
- Power……………… 41%
- Captive Power …….. 16 %
- Domestic Gas ……... 16 %
- Industry ……………. 17%
- Fertilizers …………... 4%
- CNG ………………. 5%
- Tea Estates / others… 1%

Each sector has its own plans to fulfil energy requirements. A sector wise analysis has been done to work out the demand.

A) Power Sector:

The power sector is the largest consumer of gas. The sector was directly under the Government and managed by the Bangladesh Power Development Board (BPDB). In the nineties, following Power Sector Reforms, the sector was corporatized with different companies for Generation, Transmission and Distribution. Later, Private IPPs and Rental players have also entered in power generation. The BPDB has its own generation as well as regulates generation by all entities. It also has controls the generation regulated Corporates as brought out in the following figure:

Fig2.6.8: Power Sector Organogram



(Source PSMP 2016)

Power Grid Company of Bangladesh (PGCB) is the bulk power transmission company, and is a subsidiary of BPDB.

The Electricity sector has grown at a CAGR of over 10% in the past decade or so. This followed a policy encouraging Private Sector (IPPs & Rental power plants) and imports from India. Under this plan substantial capacity has been installed by a number of Private entities on Gas, HSD & HFO. As per BPDP, the capacity addition in the year 2018-19 was about 3,493 MW, a growth of above 18% over previous year. Out of this, 3,493 MW was added by BPDB and the rest by Private sector. The peak demand during the year 2018-19 was expected to be 13,044 MW and actual demand met was 12, 893 MW. It is believed that unmet Peak demand was only 53 MWs. The generation was about 72 Billion Units (BUs), a growth of about 13% over previous year.

i) Installed Capacity–mix in Bangladesh: Thermal power (Gas, HFO, HSD & Coal) comprises almost the entire installed capacity. There are different types of thermal technologies, i.e., Reciprocating engines, Gas Turbine plants (Combined Cycle as well as Open Cycle) and Coal-fired power plants as explained in the table 2.6.2 below:

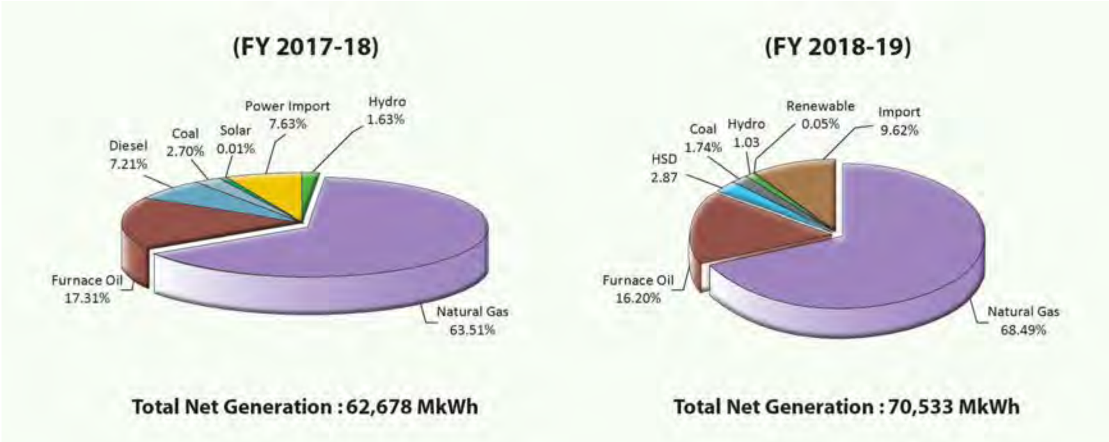
Table -2.6.2: The installed capacity-mix of Bangladesh

By type of plant		By type of fuel	
Hydro	230 MW (1.21%)	Hydro	230 MW (1.21%)
Steam Turbine	2,344 MW (12.36%)	Gas	10,877 MW (57.37%)
Gas Turbine	1,607 MW (8.48%)	Furnace Oil	4,770 MW (25.16%)
Combined Cycle	6,364 MW (33.56%)	Diesel	1,370 MW (7.23%)
Power Import	1,160 MW (6.12%)	Power Import	1,160 MW (6.12%)
Reciprocating Engine	7,226 MW (38.11%)	Coal	524 MW (2.76%)
Solar PV	30 MW (0.16%)	Solar PV	30 MW (0.16%)
Total	**18,961 MW (100%)**	**Total**	**18,961 MW (100%)**

(Source: Annual Report 2018-19 of BPDB)

ii) Generation: In 2018-19, more than two-thirds of generation was from Gas fired plants (Open Cycle & Combined Cycle). HFO-based plants accounted for about one-sixth of the generation. Power import from India was about 10%. The remaining electrical energy was contributed by HSD (3%), Coal (2%) and remaining 1% from Hydro and Renewables. As per BPDB, the source-wise share in 2018-19 and as compared to previous year is as follows:

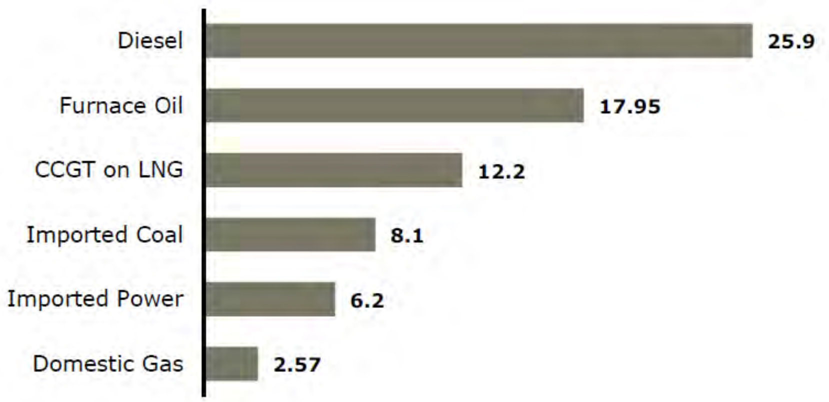
Fig: 2.6.9.: Source-wise Net Generation in 2017-18 & 2018-19



(Source: Annual Report 2018-19, BPDB)

iii) Energy Costs: In view of low gas tariffs, Energy costs on gas are the lowest as compared to other sources. The demand for gas is therefore high for power plants. As per Bangladesh 7th Five-Year Plan (2015), generation costs were lowest on gas at 2.57 taka/kwhr as compared to the other fuels. It was highest on Diesel at 25.9Taka/kwhr as illustrated in the figure 2.6.10 below:

Fig 2.6.10: Electricity generation Costs (in BDT / kwhr) in 2015



As per BPDB, the average generation cost in 2018-19 was 5.95 Tk/kwhr. Gas-based plants contributed 68% generation and its energy costs were in the range of 2.5 to 3.9 taka/kwh, amongst the lowest (except Hydro). For Coal-based plants, the energy costs were around 8.0 Taka/kwhr. One sixth of power is contributed by HFO-based plants and the energy costs were in the range of 12 to 22 Taka/kwhr. The cost of HSD-based power was also quite high, in the range of 20 to 42 Taka/kwhr. Following is the cost of energy procured by BPDB from its own plants, Public Sector Companies, IPPs, & Rental plants:

Table -2.6.3: Source-wise Cost of Generation of BPDP in 2018-19

Source-wise Cost of Generation of BPDP in 2018-19 (From AR 2018-19 of BPDB) (Energy Cost in BDT/kwhr, Energy in BUs)								
Source	Own Power		Power from Public		Power from IPPs/SIPP		Power from Rental	
	Cost	Energy	Cost	Energy	Cost	Energy	Cost	Energy
Hydro	1.6	0.7						
Gas	2.5	13.1	2.8	16.6	2.6	13.1	3.9	3.6
Coal	8.3	1.2						
HFO	17.4	1.2	20.7	0.3	12.8	7.5	14.8	2.3
Diesel	22.7	0.6	20.7	0.7	42.8	0.6	22.2	1.1
Wind	81.2	0.0						
IPP Solar	15.3	0.0	0.0	0.0	12.2	0.0		
Total	4.6	16.7	17.9	21.2	7.4	21.2	8.8	7.0
Imported Power	5.5	6.8						

(Source: BPDB AR 2018-19)

Financial and other performance parameters:

Electricity Tariffs & Subsidies: Similar to gas tariffs, the electricity tariffs for generators as well as sale of electricity are determined by BERC in close consultation with the generators, sector experts, economist and above all the government. The tariffs are subsidised and do not fully remunerate the fuel costs, finance costs, administration and costs incurred for purchase from Private IPPs & Rental power plants. As per the account statements in BPDB's Annual Report, Bangladesh government provided a subsidy of about 79.67 Billion BD Taka in 2018-19, which helped BPDP to close its accounts for the year with a nominal loss of just about 174 Million BD Taka. The cumulative losses of BPDB are 580 Bn Takas, which has been subsidised with budgetary support from the government. The subsidy in 2018-19 works out about 1.13 Taka/kwhr.

Annual PLF: The ownership-wise PLF in 2018-19 was as follows:

- Public Sector: 46.3%
- IPP: 33.89%
- Rental: 42.0%

T&D Losses: The Transmission & Distribution losses have been minimised over the years, and during 2018-19, they were just under 12%.

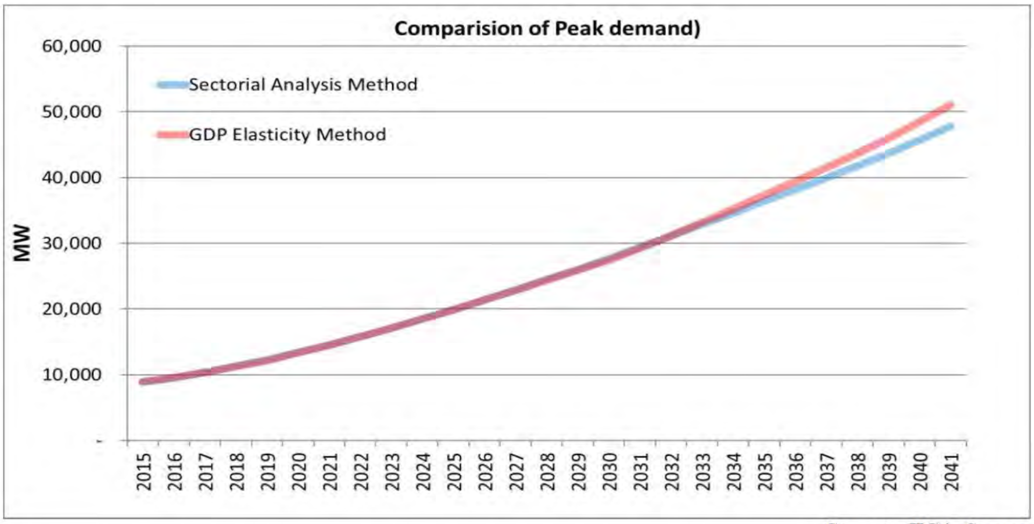
iv) Capacity Addition Plan: The country prepares a Five-year plan for all sectors of economy. The 7th Five-year plan covers the period 2015-20. Bangladesh also prepares a Power Supply Master Plan (PSMP), which is updated every 5 years. The PSMP 2016 was sponsored by Japan International Cooperation Agency (JICA) in consultation with Tokyo Power and Power Division, Bangladesh. The PSMP was drawn with the vision of Bangladesh becoming a 'High Income' country by 2041.

The PSMP 2016 has been a detailed exercise for projection of demand for power and meeting it with optimum resource mix. The methodology was to project the growth with macroeconomic targets and verify the same with sector specific micro-analysis of target growth and its conversion into the demand. The microanalysis considered all energy supply options like coal, gas, renewable, (solar, wind, hydro), nuclear and imports from neighbouring countries and also the Climate Change/ INDCs as committed in the Paris Agreement. It also laid out the scope of efficiencies in supply and demand side, i.e., optimum technology selection for economic generation, optimising operations & maintenance, efficient energy consumption, retirement of inefficient generating plants, reducing the reserve generating capacity for peak and base loads, transmission, distribution and its monitoring, planning for infrastructure for import of coal, gas and electricity.

It projected several scenarios considering the GDP growth and its elasticity with corrections for improvements in energy intensity over time. The price volatility and availability of oil, gas & coal can also impact plays in the scenarios. It considered the candidate sources of generation and optimised the selection. It also mapped the development of infrastructure for an healthy fuel supply chain. On the tariffs front, it advised policy interventions for removing subsidies and advised several policy measures for tariffs and realization.

The PSMP 2016 has mapped the projections of peak demand by GDP Elasticity method as well as by Sectoral Analysis (Ref Fig 2.6.11 below).

Fig 2.6.11: Comparision of Peak demand by GDP Elasticity and Sectoral Analysis



Source: JICA Survey Team

(Source PSMP 2016)

Accordingly, the growth of demand and energy has been finalised and as per the Annual Report for 2018-19, BPDB has projected capacity of 21,000 MW by 2021, 31,000 MW by 2030 and 57,000 MW by 2041. The Peak demand and capacity targets are mapped in the table below:

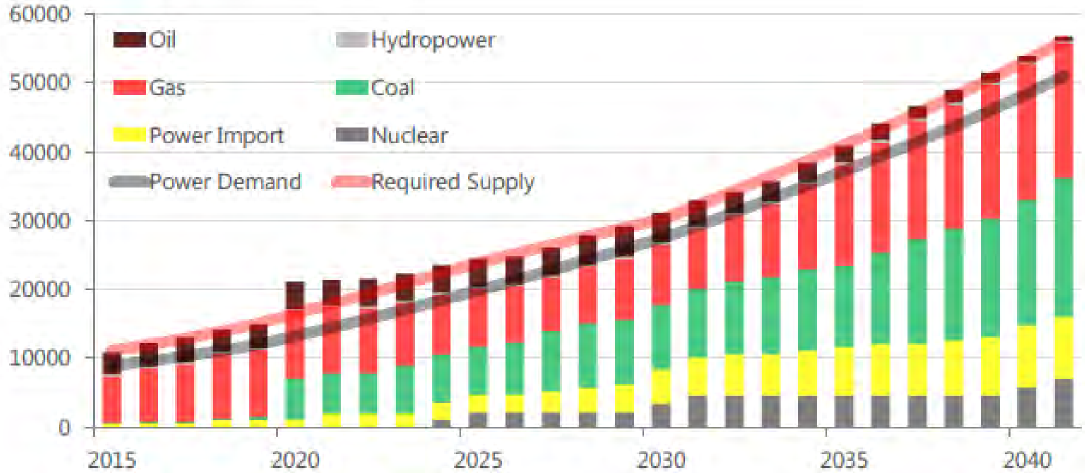
Table -2.6.4: Long-term Peak Demand and Generation Capacity

Long Term Peak Demand and Generation Plan				
Year	2019	2021	2030	2041
Projected Peak Demand (in MWs)	13,044	14,500	27,400	51,000
Planned Gen Capacity (in MWs)		21,000	31,000	57,000

(Source AR 2018-19 BPDB, Author)

Source-wise Growth Projections: Amongst five scenarios projected by JICA, the Power Scenario-3 has been accepted as the Base Case . This scenario projects the installed capacity to be around 57,000 MWs by 2014 with coal and gas to have a share of 35% each as shown in Fig 2.6.12 below

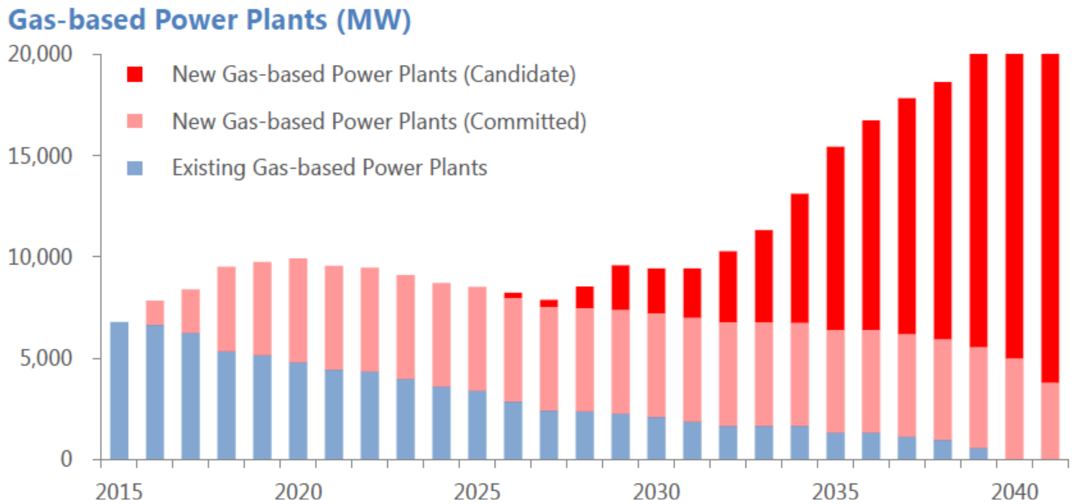
Fig 2.6.12: PSMP 2016: Power Development Plan in MWs (Base Case Scenario)



(Source: PSMP 2016, JICA)

Retiring of ineffiecient capacities like open cycle or gas-based reciprocating engines has been envisaged in a time bound manner as below:

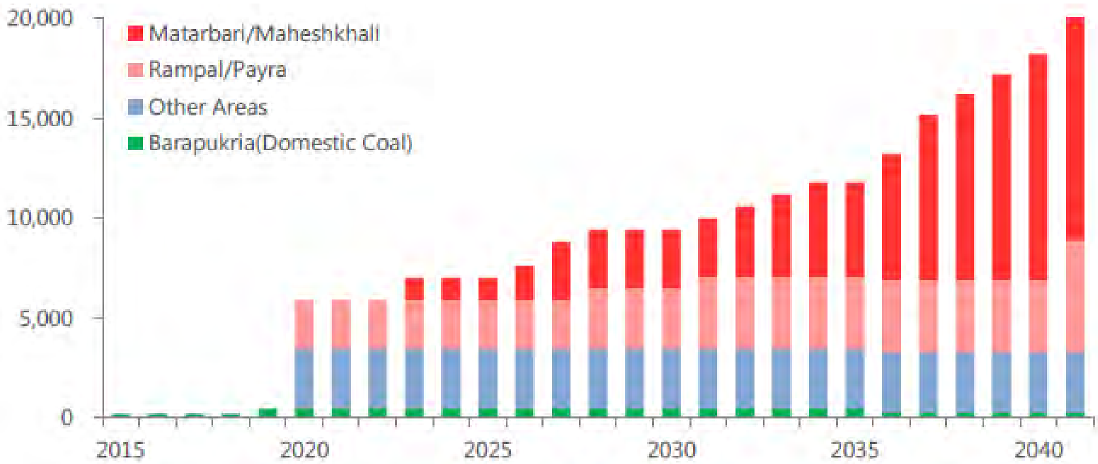
Fig2.6.13: Addition of New Gas-based capacity and Retiring of Existing plants



(Source: PSMP-2016 / JICA)

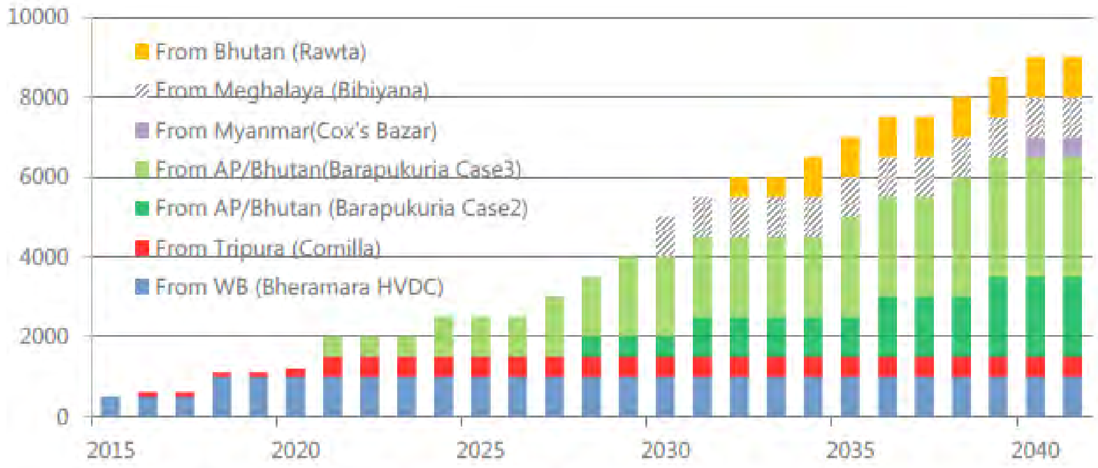
The PSMP-2016 also projects year-wise capacity addition of Coal-based, Nuclear and year-wise increase in Power Imports as per this scenario. (refer figures 2.6.14, 2.6.15 and 2.6.16 below).

Fig 2.6.14: Addition of New Coal-based capacity alongwith the Candidate Plants



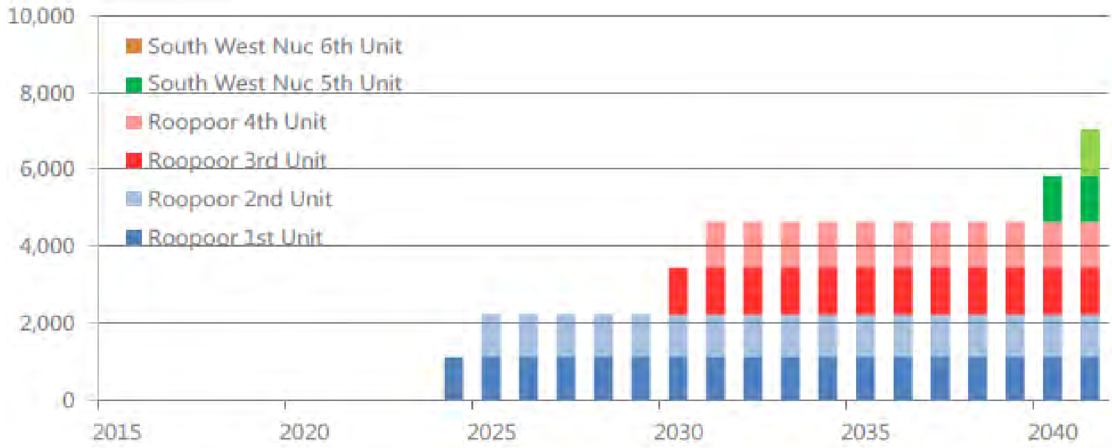
(Source: PSMP-2016)

Fig 2.6.15: Addition of Power Imports from neighbouring Countries



(Source: PSMP-2016)

Fig 2.6.16: Addition of Nuclear Power Capacity Addition with Candidate Plants



(Source: PSMP-201 /JICA)

Committed planned capacity additions from 2019 – 2023: About 17,905 MW of capacity additions are already under implementation. Out of this, about 5,289 MW capacity is on Gas. Source-wise capacity additions under implementation are as follows:

Table-2.6.5: Year-wise Capacity Addition by energy source 2019 to 2023

Year-wise Capacity Addition by energy source 2019 to 2023 (in MWs)						
Source	**2019**	**2020**	**2021**	**2022**	**2023**	**Total (2019-2023)**
Gas	1164	690	400	1168	1867	5289
Gas / HSD Dual Fuel	361	0	336	420		1117
HSD	0	0	161	0	0	161
HFO	2187	496	0	0	0	2683
Coal	0	1320	1320	1224	2947	6811
Solar	8	0		0	0	8
Hydro	0	0		0	0	0
Import	0	0	340	1496	0	1836
Total	**3720**	**2506**	**2557**	**4308**	**4814**	**17905**

(AR 2018-19, BPDB, Author)

Forecast of gas demand for Grid-based power

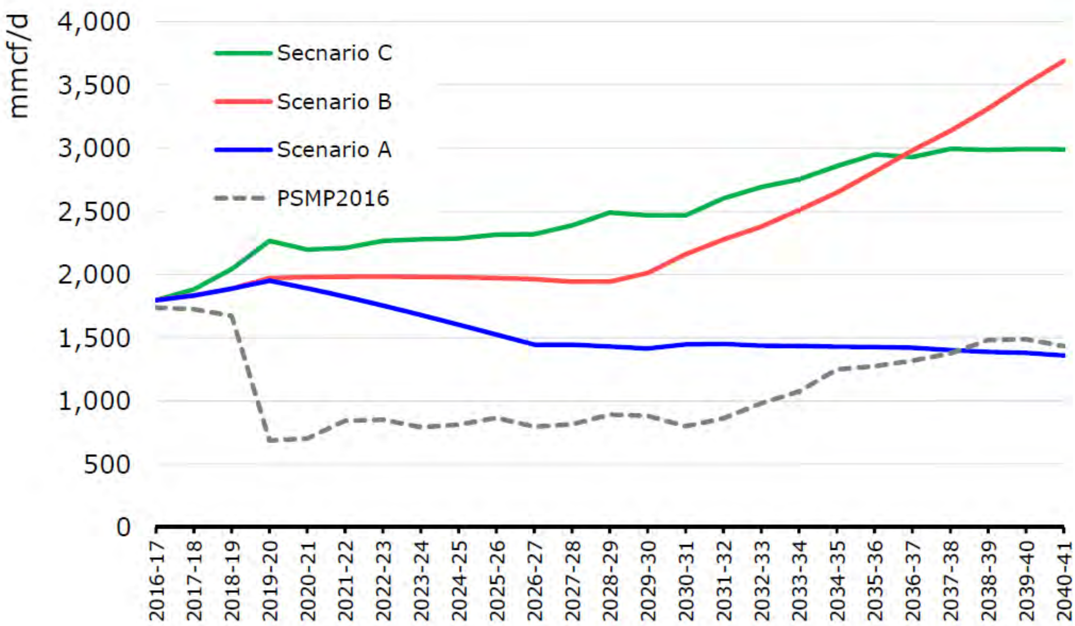
The PSMP was followed by development of a Gas Supply Master Plan 2017 (GSMP 2017), which was developed by Ramboll for MPEMR / Petrobangla. The projections of gas demand for power sector was drawn from the PSMP 2016 projections for gas based capacity in the Power Development Plan (Base Case Scenario). The 'Base Case' in PSMP 2016 had projected about 57 GW of capacity in 2041, with share of Gas and Coal at 35% each, Imports at 15%, Nuclear at 10% & balance 5% for Renewables & others.

GSMP 2017 corrected the delays in implementation of the coal-based generation capacity, and draws three scenarios for Power Sector for projecting gas demand:

1. **Scenario A: Modified PSMP:** The Scenario assumes same demand projections and GDP growth projections as in PSMP2016. The GDP in 2041 reaches 4 times the GDP in 2016-17. The scenario also takes into account delay in coal based plants upto 2018 vis-a-vs the projections. This will delay decommissioning of some inefficient gas-based plants and is likely to change the demand pattern. The share of gas in the power-mix would come down gradually from current 68 – 70 % to about 35% by 2041 as coal takes over. The demand in 2041 is about 1,358 mcfd and similar to projections in PSMP2016.
2. **Scenario B: High Growth:** Taking cue from the prevailing trend of soft oil & gas prices, and, a high GDP growth, this scenario sees gas demand levels reach 2000 mcfd in 2020 and then stabilise with replacement by efficient plants helping increase in generation, before increasing to 3,690 mcfd by 2041. This is a 'dominant gas' scenario.
3. **Scenario C: Climate Change:** This scenario factors in less capacity addition in Coal-based plants. It also factors in the growth of Renewables in the later years, which curtails the demand for gas by power sector. Gas demand would reach 2,266 by 2020 and then steadily reaches 3000 mcfd by 2041. The GSMP names this scenario as 'Climate Change' scenario.

As per GSMP 2017, the demand projections for Grid-based power are as under:

Fig 2.6.17: Gas Demand Forecast for Grid-based Power



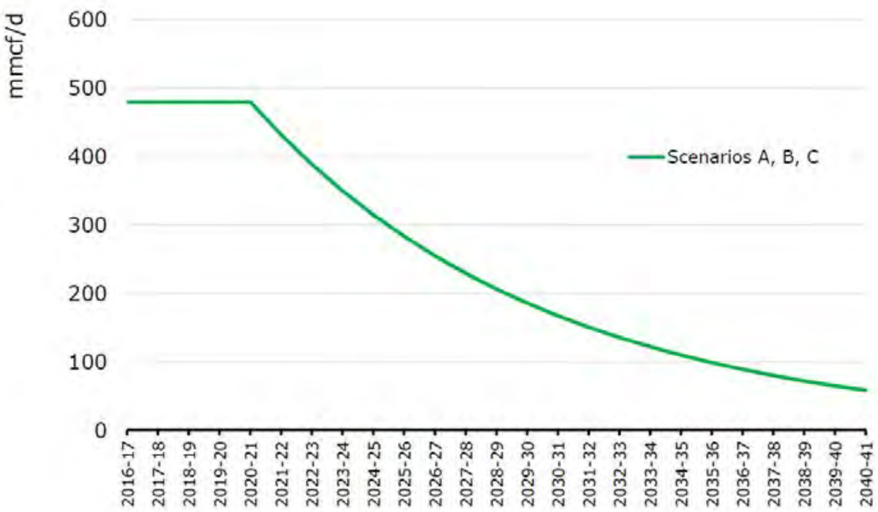
(Source GSMP 2016 and Ramboll's adjustments in consultation with Petrobangla)

(B) Gas Demand for Captive Power

The common issues across the industries (Textiles, Steel, Cement, Glass, Sanitary, Tiles, Ceramics, Agro etc) is that captive power generation on gas supply is cheaper by 30 - 60% as compared to the grid power. It is the shortage of gas that compels the industry to depend on the grid power. The price correction in gas supplies to industry had been recommended in the PSMP 2016 and also in GSMP 2018. The BERC has increased the prices in 2017 & 2019 and now, gas prices for captive power are over three times that for Power and Fertilizers. The PSMP 2016 had also recommended that more reliable grid power be provided to industries and captive power is to be slowly phased out except for industries like ceramics, steel and glass where production processes take substantial time to recover from loss of power and therefore some captive back-up power is essential.

The existing consumption of Captive Power is about 480 mcfd and is likely to come down as new Grid Power capacity comes on line. The demand projected in GSMP 2018 is as follows:

Fig 2.6.18: Gas Demand Forecast for Industries



(Source GSMP 2018)

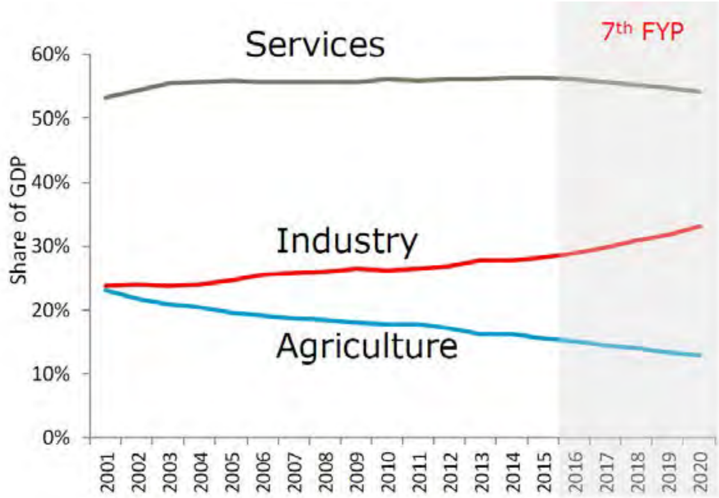
(C) Gas Demand for Fertilizers

The total capacity of Urea-Ammonia based fertilizers in Bangladesh is about 3.515 MMT/annum and the gas demand is about 300-325 mcfd. However, due to shortage of gas, the plants do not operate at full capacity and the country imports about 50-60% of its Ammonia-Urea requirement. The gas available for the Fertilizers is between 130-140 mcfd. Another factor is that the Fertilizer plants of Bangladesh consume more gas (45 mcf/ton of production) than the world standard of 25 mcf/ton.

(D) Gas Demand for Industry

The gas consumed by Industry in 2018-19 was about 17% or about 455 mcfd, suggesting an unmet demand over 100 mcfd. Besides, the GoBD plans to step up its exports in textiles and other key products and has already planned Special Economic Zones for exports. The share of industries in the GDP in its 7th Five-year Plan(2015-20) is likely to increase from about 26% to about 34% by the end of plan as follows:

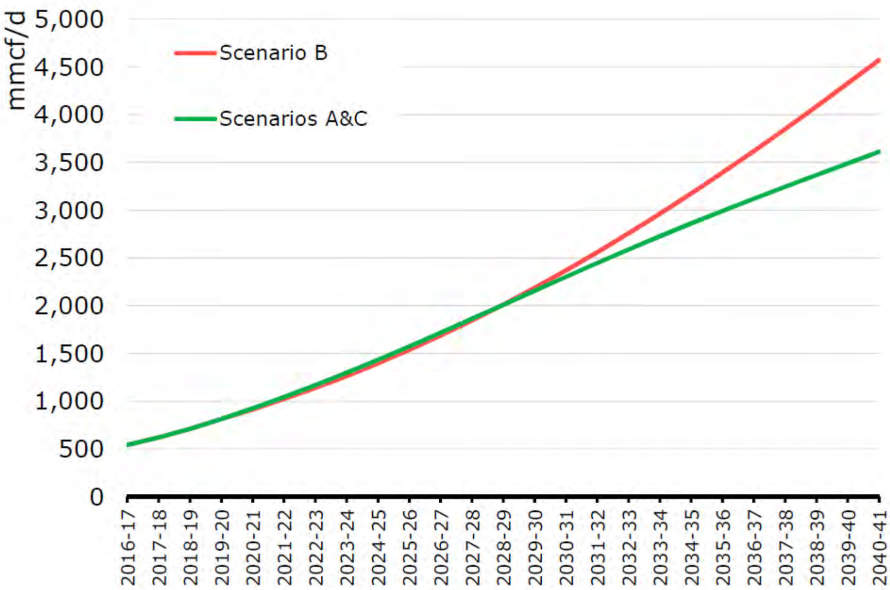
Fig 2.6.19: Bangladesh share of sectors in GDP



(Source World Bank, GSMP 2018)

The Bangladesh Energy Efficiency and Conservation Master Plan has a target of of 10% reduction in energy consumption by industries in the Business as Usual scenario. As per the GSMP 2018, Assuming a Scenario 'A', reflecting conservative GDP growth rates (existing 7-8% and gradually declining to about 4% in 2041), and elasticity from 2.05 gradually declining by 60% in 2041 as efficiencies set in, the gas consumption in industries would be increasing to 3,600 mcfd by 2041. However, the Bangladesh government is quite committed to see the GDP maintain between 6.5-7 % (Scenario 'B' & 'C'), the gas demand may grow to around 4,200 mcfd in 2041, as shown in the following figure:

Fig 2.6.20: Gas Demand by the Industry in High/ Moderate GDP Growth rates

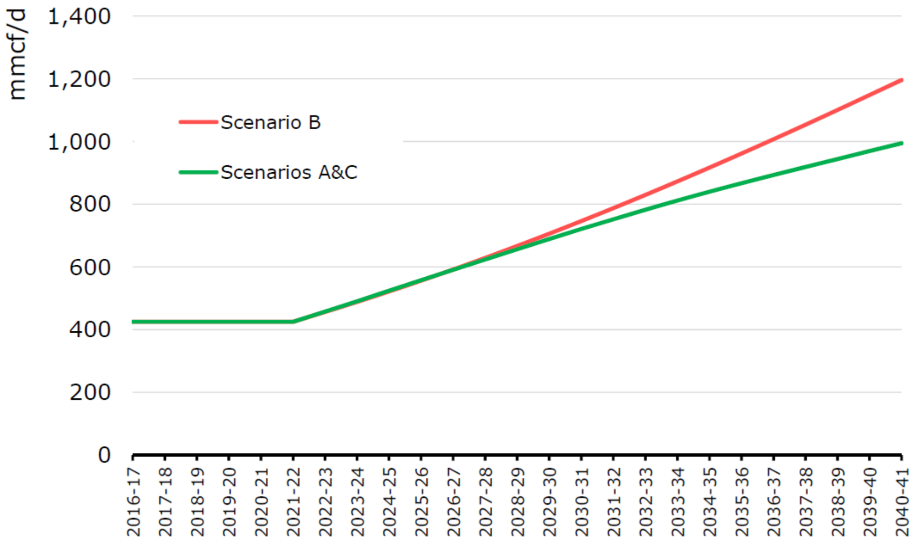


(Source GSMP 2018)

(E) Gas Demand for Domestic households

At present Bangladesh supplies majority of domestic gas on fixed monthly fees basis. This has set in inefficiencies in its economic use. Besides, a majority population uses Biomass for cooking fuel and there is a demand to supply cooking gas to this chunk of population. As a corrective measure, the installation of Pre-paid meters has commenced and is gaining momentum. As per the Energy Efficiency and Conservation Master Plan, the country has plans for improving the efficiency of cook stoves and 10% switch from Biomass to LPG. Besides, 100% switch to LPG may not be limitation in its domestic production and high prices for imports. As such, the demand projections consider the elasticity with GDP growth in 2004-2014 from 2022 onwards, albeit pinned down to 50% due to efficiencies. The demand increases to about 750 mcfd by 2030 and in the range of 1000 -1200 mcfd by 2041 as in figure 2.6.21 below:

Fig 2.6.21: Gas Demand Forecast for Domestic Gas



(Source: Ramboll , GSMP 2018)

(F) Gas Demand for Commercial sector

The correlation between GDP and demand of gas in the period 2004-2014 was not found to be good enough to suggest adopting elasticity methodology for commercial sector demand in coming years. Besides, the government has planned to switch some CNG to LPG. As such, the demand is likely to stay stabled at around 40 mcfd.

(G) Gas Demand for CNG

Introduction of CNG in Bangladesh began as early as 1989. There are about 599 approved CNG filling stations and about half a million CNG vehicles. However, the shortage of gas has compelled Bangladesh to discourage CNG. The government has also tried to use LPG to substitute gas.

With the present prices of petrol and diesel, switch-over to CNG is more economical.

Table-2.6.6: Comparison of cost of thermal energy in CNG, Petrol and Diesel in Bangladesh

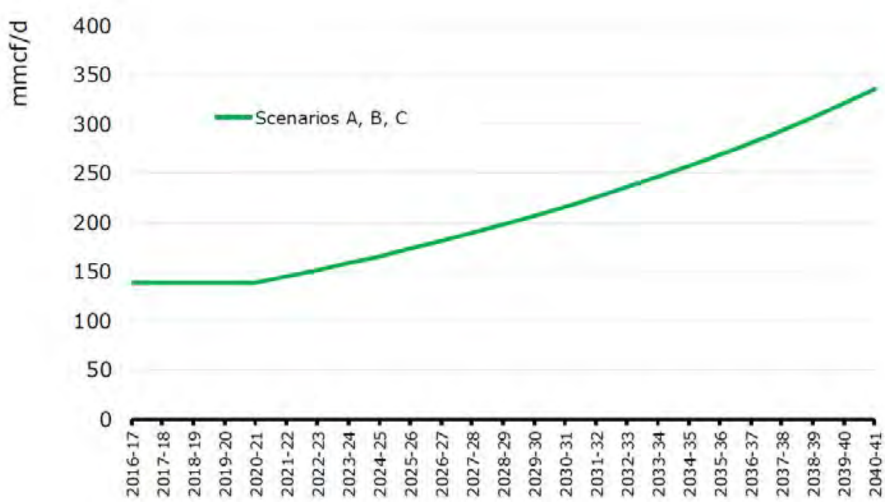
Comparison of cost of thermal energy in CNG, Petrol and Diesel in Bangladesh

Fuel	Price	Unit	GCV	Unit	Price In BDT/1000 Kcals	Price In USD/ mmbtu
CNG	43	BDT/cum	10000	Kcals/cum	4.3	13.55
Petrol	89	BDT/Litre	8269	K cals/litre	10.76	33.92
Diesel	65	BDT/litre	9185	Kcals/Litre	7.08	22.30

Notes
1. GCV of Petrol is 11,100 Kcals/Kg and density is 0.745 Kg/litre
2. GCV of Diesel is 11,000 Kcals/Kg and density is 0.835 Kg/litre
3. Exchange rate is 1 USD = 80 BDT
4. Conversion from Kcals to btu: 1 K cal = 3.966 btu

A report by Exxonmobil projects an annual growth rate of 4.5% in the demand for gas in the transport sector till 2040. The introduction of LNG in the supply basket in Bangladesh is viewed as a key enabler for the expansion and penetration of CNG. The GSMP has projected the demand of CNG sector to pick up from 2020 onwards and grow from 139 to 335 mcfd between 2020 to 2041 as in the figure 5.6.22 below:

Fig 5.6.22: Gas demand for CNG Sector in Bangladesh



(Source: GSMP 2018, Ramboll)

2.6.6 Summation: Gas Demand of all Sectors

Scenario A: Modified PSMP 2016

As coal based generation picks up, the gas demand from power sector declines. The inefficient gas plants shall retire in due course. The CNG growth would continue. The demand from industry and domestic sectors shall witness strong growth and consume 69% of gas. The demand in 2040-41 reaches 6,713 mcfd**Scenario B: High Growth (About 8% GDP Growth rate , Share of Gas in Power -40%)**

While the share of gas in power shall decline, the share of consumption in Industry, domestic and CNG sectors are likely to grow strongly as GDP growth rates are close to 8%. The demand for gas reaches 6,012 mcfd in 2030-31 and 10,208 mcfd in 2040-41.

Scenario C: Climate Change: (power is 36% share)

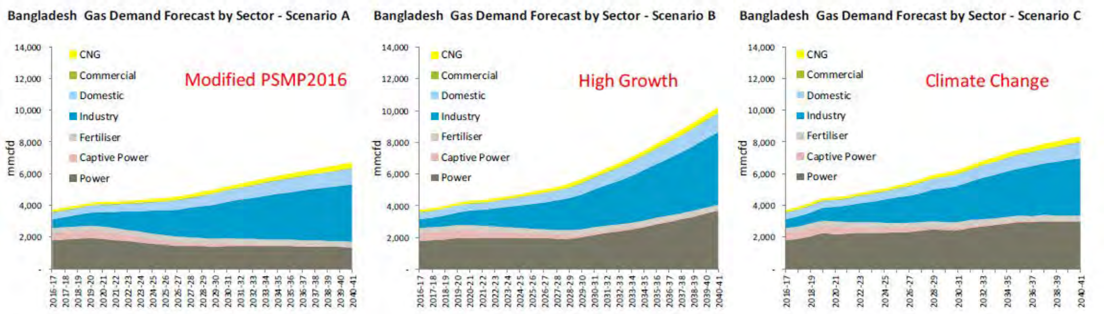
Scenario C projects gas demand in all sectors similar to Scenario A except in Power Sector. As climate change threatens Bangladesh with serious implications, the power sector growth shifts from Coal to gas in order to align the Carbon-di-oxide emissions with the commitments in Paris Agreement. The share of gas is about 3000 mcfd for power sector, and total demand reaches 8346 mcfd by 2040-41.

As per GSMP 2017, the demand for Fertilizer and Commercial shall remain constant in all scenarios. The demand in different scenarios in 2025, 2030 & 2040 are tabulated as under:

Table-2.6.7: Gas Demand in mcfd (as per GSMP 2017)

Year	Scenario A	Scenario B	Scenario C
2025	4467	4876	5257
2030	5207	6012	6228
2040	6713	10208	8346

Fig 5.6.23: Gas Demand in the three scenarios in GSMP



The gas demand projections, rounded off to the nearest 50 mcfd shall be as follows ;

Demand in 2025: 4450, 4900 & 5250 mcfd in Scenario A (Modified PSMP), B & C respectively

Demand in 2030: 5200, 6000 & 6200 mcfd in Scenario A (Modified PSMP), B & C respectively

Demand in 2040: 6700, 10200 & 8300 mcfd in Scenario A (Modified PSMP), B and C respectively

2.6.6: Demand – Supply Gap & analysis

A) Scenarios

The gas demand- supply gap analysis has been done in four combinations of growth in Demand and domestic Gas production from the Proven, Probable, Possible (3P) and Yet to Find (YTF) reserves.

Demand scenarios for this analysis are the 'Modified PSMP' and the 'Climate Change' as per the GSMP 2017. The Modified PSMP takes into account the delay in addition of coal-based capacity and the 'Climate Change' scenario has more Gas-based and Renewables-based than coal-based capacity addition, with contribution of gas-based power rising to almost 40% in the energy basket by 2041.

The Supply scenarios are '3P + YTF of 6.4 tcf' and the '3P + YTF of 34 tcf'. The former is more 'Realistic' while the latter is based on 50% probability of YTF reserves, mainly Off-shore, supported by discoveries in neighbouring Myanmar.

The four Scenarios are as follows:

- **Scenario 1: Demand as per 'Climate Change' and Supply as per Realistic (3P + YTF of 6.4 tcf)**
- **Scenario 2: Demand as per 'Climate Change' and Supply as per High Exploration (3P + YTF of 34**
- **Scenario 3: Demand as per Modified PSMP and Supply as per Realistic (3P + YTF of 6.4 tcf)**
- **Scenario 4: Demand as per Modified PSMP and Supply as per High Exploration (3P + YTF of 34 tcf):**

The emerging gap in Demand –Supply in 2025, 2030 & 2040 is as follows:

Table-2.6.8: Demand -Supply Gap Analysis

	Year 2025	Year 2030	Year 2040						
	Demand	Supply	Gap	Demand	Supply	Gap	Demand	Supply	Gap
Scenario 1	5250	3000	2250	6250	2500	3750	8300	500	7800
Scenario 2	5250	3000	2250	6250	4750	1500	8300	2500	5800
Scenario 3	4450	3000	1450	5200	2500	2700	6700	500	6200
Scenario 4	4450	3000	1450	5200	4750	450	6700	2500	4200

B) Demand – Supply Gap Analysis:

The following factors could affect the demand in the spects are important to consider:

a) Climate Change & Surplus / Soft LNG markets: Bangladesh is exposed to the vagaries of floods and cyclonic storms which hits its Agriculture as we'll as economy. Measures for combating climate change are therefore important and coal-based capacity addition may not find favour in these times. Besides, installing coal-based plants raise serious environmental concerns and resistance from the locals.

b) Slowdown of growth post- COVID: The post-pandemic slowdown is likely to affect the demand in the short to mid-term.

c) Delay in Off-shore exploration: The exploration activities in the Shallow Off-shore as well as Deep-sea blocks are facing challenges and delays. Besides, it could be that the off-shore blocks may not achieve success rate in discoveries as experienced in the on-shore blocks in the past.

The Scenario -4 has the least gap and can be the reference for planning of imports. The gap of 450 mcfd in 2030 may actually be higher as the delays in exploration of the Off-shore blocks (SS-04, SS-09 & SS-11) as well as Deep Off-shore blocks (DS-12) may delay the prospective discoveries and their appraisal, development and production may get deferred. The demand –supply gap as per demand and domestic gas production clearly establishes the need for gas imports by LNG or Pipeline mode. RPGCL, the nodal organization for import of LNG foresees a demand of 6787 mcfd and has planned import of about 4,000 mcfd of LNG in 2041.

C) Mitigating the gaps:

Other than the domestic production, the proposed supply sources are as follows:

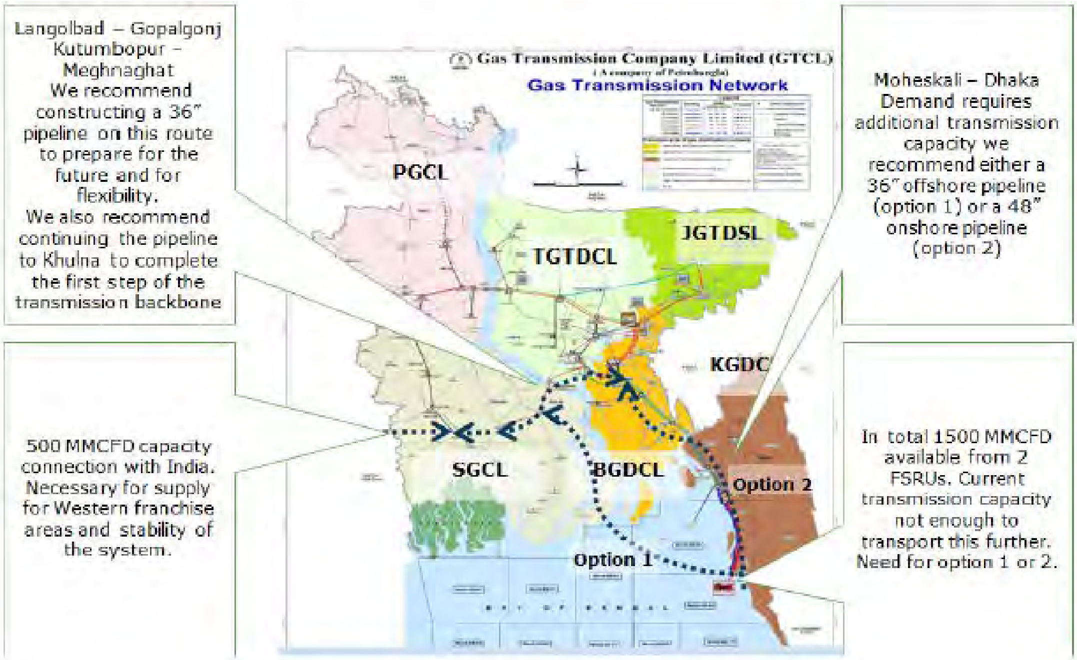
(i) Short to Mid – term (2025 – 2030) , the gas shortage is only 1450-2250 mcfd till 2025 and thereafter can increase to 1,500 - 3,750 mcfd by 2030. The shortages can worsen if there is delay in development of YTF gas reserves. Bangladesh has already installed two FSRUs of total 1,000 mcfd capacity. Petrobangla/GTCL and Ramboll carried out pipeline simulation studies with 'Pipeline Studios', a simulation modelling software, using data on the expected demand in the Climate Change scenarios for all the gas distribution companies, pipelines under construction and capacity of the pipeline network for a short to mid term. They used a software 'Pipeline Studio' for their simulations.

Key findings from simulations in Pipelinne Studio indicated a shortfall of 500 mcfd in 2021. The shortages are likely to be felt in areas at the end of the Transmission network, mainly Khulna under SGCL Zone. Based on the output, the GSMP consultants, have proposed the following:

1. An additional RLNG Terminal at Moheshkhali
2. A large onshore pipeline connectivity from Moheshkhali to the west of the country
3. A connection with India at Satkhira post near Khulna.

The pipeline connectivity with India at Khulna would improve pipeline hydraulics and provide system stability, security of supplies and improve bargaining power of Bangladesh with external suppliers. The above simulations were done with the assumption of 1500 mcfd from FSRUs. Incidently, with existing FSRUs, only 1000 mcfd can be supplied. This constraint would add further strain on the transmission systems. If the Indian connectivity does not come up, or there is delay in domestic gas production and demand rises as projected, another FSRU would be required at Moheshkhali with expansion of pipelines.

Fig 2.6.24: Recommendations in GSMP for Short-term stability of Transmission System



(Source: GSMP, Ramboll)

Earlier, during demand-supply analysis in PSMP 2016, for meeting the gas shortages, a cross border link with India as follows was proposed:

Fig 2.6.25: Proposed Interconnecting Pipeline link with India

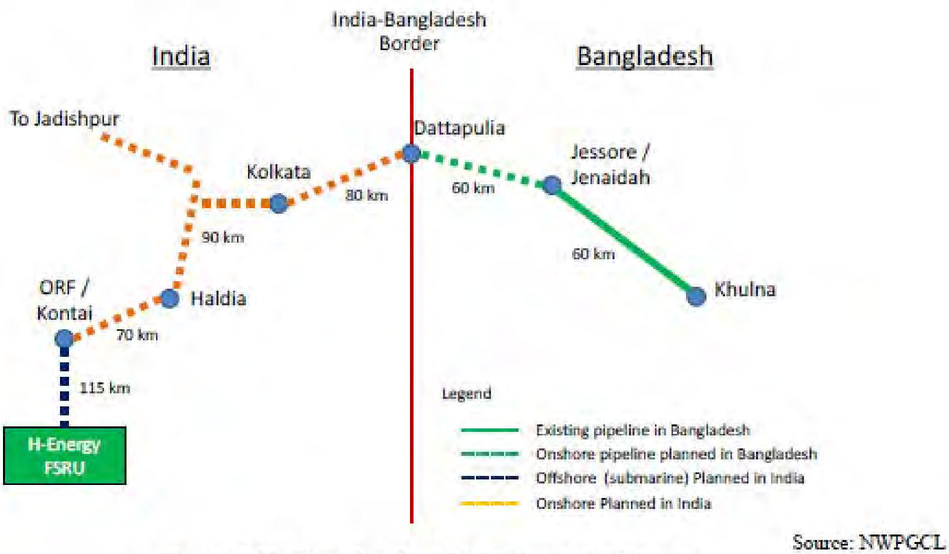


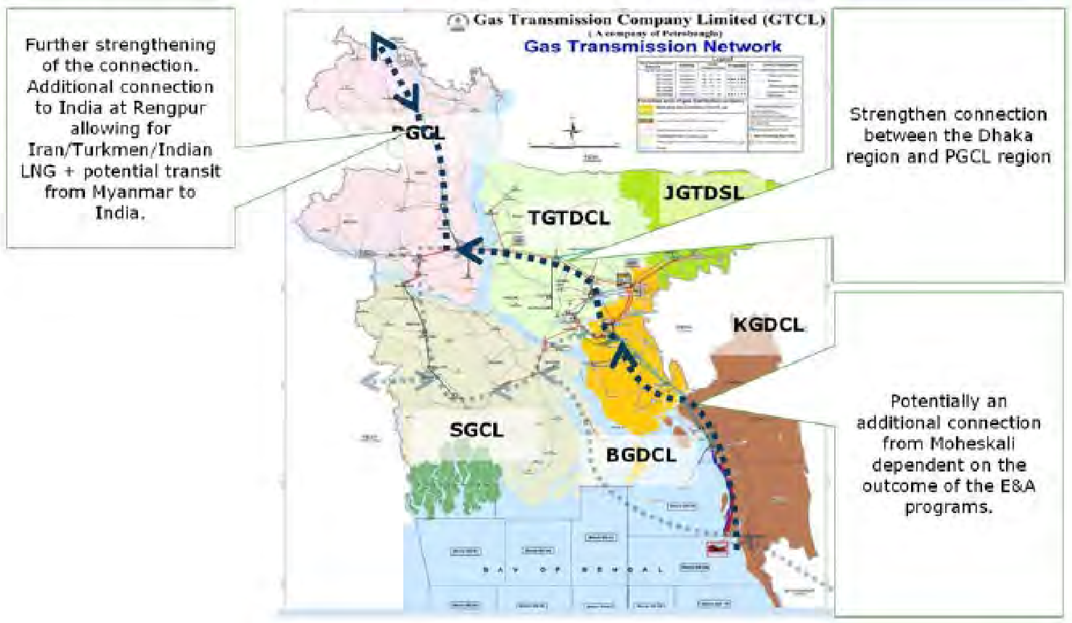
Figure 8-11 Cross-border LNG Schematic Diagram

(Source PSMP 2016)

(ii) Mid to Long-term (2025 and beyond): In the simulations, the shortfall in gas supply and network capability is expected across all regions, but more in Khulna and Sunderbans, which are at the South–eastern tips. The GSMP 2017 has recommended a third LNG terminal at Moheshkhali and a fourth, a land-based one at Matarbari. RPGCL and the EMRD are exploring feasibilities for Land-based LNG Terminals. An EOI was invited in Jan 2019 for a land based RLNG terminal near Matarbari of 7.5 MTPA (1000 mcfd) on 'BOOT' basis with transfer to be after 20 years of Operation.

Bangladesh's coastline is exposed to frequent storms & cyclones from Bay of Bengal. After a careful research of sea and wave movement data, the coast on the South-eastern tip around the Cox Bazaar is identified as the most suitable location for FSRU / LNG Regasification Terminals. As the demand centres are away in the north, investments in large sized trunk pipelines is required to fulfill the long-term demand in the other regions. The GSMP 2017 has recommended a large diameter 500-km long pipeline from Myanmar to India via Bangladesh for the long-term. The pipeline would help to balance the hydraulics and avoid laying of additional pipelines to evacuate the LNG Terminals/FSRUs around the Cox Bazaar. This pipeline would be connected from Rangpur in Bangladesh to Kishanganj in India with GAIL's Barauni-Guwahati trunk pipeline as in the figure below:

Fig 2.6.26: Proposed Long-term Strategic Plan for Intra Regional Connectivity



(Source Ramboll, GSMP)

This pipeline shall serve multiple purposes:

a) Improve system stability

b) Provide flow of surpluses between Myanmar, Bangladesh & India

c) Regional integration for future connectivity of India with Turkmenistan (TAPI) or Iran (IPI).

(iii) The economics of supplies from India

As discussed table 2.6.6 above, based on the latest pricing of its CNG, Petrol and Diesel in Bangladesh, the Petrol costs about 33 $/mmbtu and Diesel costs about 22 $/mmbtu.

Iterations were carried out for delivery prices Ex-India borders for Long-Term and Spot or High Seas Sale cargoes at India's RLNG terminals. For LT RLNG, DES prices were assumed at Crude parity of 12.6% plus 50 cents, Regasification at 1 $/mmbtu, Tptn at 1 $/mmbtu and all taxes and marketing margins as per prevailing rates. For Crude between 40 to 50 $/bbl, ex-India prices could be in the range of 9 to 10.5 $/mmbtu.

For Spot Cargoes at 6$/MMBTU Ex Terminal, the prices would be around 7.5 $/mmbtu. For cargoes on 'High Seas' sales at say 4 $/mmbtu, the prices Ex India prices would be about 6$/mmbtu

Delivered price Ex- India for LT/Spot RLNG ,Adani Gas Dhamra (April 2020)					
Particulars	**Long Term RLNG**	**Long Term RLNG**	**Long Term RLNG**	**Delivered Spot RLNG ($/mmbtu)**	**High Sea Spot RLNG ($/mmbtu)**
Crude Price	50	40	45	6	4
Delivered Price in USD/ MMBtu	**10.49**	**8.95**	**9.72**	**7.40**	**5.99**
Exchange Rate USD / INR	**76.00**	**76.00**	**76.00**	**76.00**	**76.00**

As can be seen above, after adding pipeline transportation and retail distribution costs inside Bangladesh, imported RLNG gas would be available at less than 20 $/mmbtu including all marketing and distribution margins.

(iv) Summarising mitigation plans

The actual demand-supply gap can vary from the Short-term, Mid-term and Long-term plans. It is imperative that the gas sourcing plan, over and above the, should be techno-economically feasible and flexible in mitigating the dynamic shortage in domestic gas production as well as the change in demand pattern. A likely Short-term, Mid-term and Long-term gas sourcing plan is proposed and tabulated as in the table 2.6.9 below

Table-2.6.9: Summary of measures for mitigation of gas shortages

Plan	FSRU	LNG Terminal	Pipelines with India /Myanmar
Short-term (2020-2025)	2		500 mcfd pipeline connectivity with India (Shrirampur - Khulna)
Mid-Term (2025-2030)	3	1	500 mcfd pipeline connectivity with India (Kishanganj - Rangpur)
Long-term (2030-40)	4	2	Connectivity with Myanmar and augmenting capacity of Kishanganj-Rangpur
Assumptions: Each FSRU is of 500 mcfd, LNG Terminals of 7.5 MTPA (1000 mcfd)			

(Sources: GSMP 2017)

The cross-border pipelines offer access to LNG and gas resources from neighbouring countries help to effectively economize investments in capacity building of FSRUs, LNG Terminals, LNG Storage & the evacuating Pipelines. These pipelines also provide dynamic stability in pipeline hydraulics and provide flexibility in mitigating dynamic shortages from different sources and the demand – supply gaps for the both the neighbouring countries.

2.7 Gas Trade

2.7.1 Gas Exchange and Hub:

Bangladesh has a reasonably good gas pipeline network, with fair degree of penetration in the central, eastern and south-eastern part. The strengthening and expansion of pipeline network in the northern, western and south-western (Sunderbans) areas have been planned. However, the gas allocations and supplies are totally under control of the subsidiaries of Petrobangla. Further the gas prices are highly subsidized control and the prices are subsidized.

Developing a Marketplace / Exchange

A gas market needs multiple buyers and sellers, a fair degree of pricing freedom, transparency in price discovery, standard terms & conditions in contracts for deliveries (derivative/physical) that encourage trade. Above all, the development of the gas markets requires strong political, regulatory and fiscal support. Bangladesh is yet to liberalise its gas marketing and distribution to enable development of an independent and free marketplace.

2.7.2 Government outreach for bilateral trade with India

India is constructing a 130-km long oil pipeline under the Indo-Bangladesh Friendship Pipline from Siliguri to Parbatipur for supplying oil products. The need for pipeline connectivity near Khulna in Bangladesh with India has already emerged as a key factor to meet the gas requirement and improve system stability. As per MoP&NG, a land-based pipeline for carrying gas from LNG Terminal at Dhamra to Bangladesh across the Satkhira border is being pursued by some Indian companies. The following three trunk pipelines on Indian side can be considered:

1. Jagdishpur – Haldia: This pipeline is under construction by GAIL, a gas marketing and distribution company. The target completion is Dec 2020.
2. Kanai-Chata – Shrirampur: This line has been authorised by PNGRB to H-Energy in July 2019. This line can provide access to Dhamra Terminal of Adani & Total (completion by 2021) and the proposed LNGterminal of H-Energy near Haldia . Connectivity is proposed at Shrirampur, which borders Bangladesh near Khulna.
3. Barauni – Guwahati pipeline of GAIL: This line is under construction by GAIL, and its completion is targeted in 2021.

Commencement of Bilateral trade would be a beginning which can help the development of a gas hub in due course of time.

2.8: Summary: Key growth driver of gas sector in Bangladesh

The exploration and discovery of gas has helped Bangladesh in its development and economic growth over the last two / three decades. Gas amounts to nearly half of its Primary energy requirement and fulfils nearly 70% of the commercial energy needs. The gas reserves are however declining and Bangladesh has installed two FSRUs for importing LNG and subsist the decline in production. The country has scant reserves of coal and a significant part of the country is under or unexplored for oil & gas. The country's history of exploration has been encouraging with one discovery in three exploration wells. It is therefore following a strategy of intensifying its exploration programme, augmenting its existing production by a work over program and installing LNG receiving facilities.

The key drivers for growth of Gas business in Bangladesh:

1. For two successive years, Bangladesh has recorded GDP growth higher than India. In its 'Vision 2041' plan, approved in Feb 2020 by the National Economic Council (NEC) headed by the Prime Minister, the country has an ambitious plan to become a developed nation by 2041. The GDP growth is targeted at 9% till 2031 and 9.9% from 2031 to 2041. The per capita annual income is targeted to reach 12,500 USD by 2041.
2. It is continuously driving its efforts and policy interventions for encouraging investments in E&P (Off-Shore as well as On-shore). Petrobangla, the NOC in E&P has launched a 5-year Plan for drilling of exploratory wells as for workover of existing wells for enhancing production with participation of its subsidiaries BAPEX & SGFCL, as well as other IOCs
3. While textiles has been a dominant contributor in exports and Forex earnings, the recent industrial growth in segments like Automotive machine parts, Ship-breaking, Shipbuilding and IT Software & Services has bolstered its basket of exports.
4. As per the Base case scenario in Power System Master Plan (PSMP 2016), by 2041, the share of coal-based capacity is likely to reach about 35%, nearly same as gas-based capacity. However, the climate change concerns and the softening of LNG prices may see course correction in favour of gas-based capacity addition plans in the power sector.
5. The gas pipeline infrastructure, already the best developed amongst BBINS countries, is being further augmented to help deliver the demand. Besides, many of the gas pipelines under construction in India are in close geographical proximity and offer potential of connectivity for supplies from LNG terminals in India, most likely from the Dhamra RLNG Terminal.

Gibraltar LNG Regasigication Terminal- Courtesy of Shell

Chapter 3: Gas and RLNG Environment in Sri Lanka

3.1 Key demographics of the Energy sector

Sri Lanka is the second richest country of South Asia after the Maldives. In 2019, Sri Lanka moved up in the 'Upper Middle-income' group as per the World Bank. In 2018, the per capita GDP of 4102 $/annum was ahead of India, with inflation just under 4.5%, and HDI at 0.78. Its GDP growth rate was over 6% in 2017 and 2018. It has been keen to exploit its hydro and other new Renewable Energy sources. It has provided access of power to 100% household, off-grid or grid-connected. By the end of 2018, its per capita electricity consumption was 650 kwhr/annum, which is a growth of about 3.8% over 2017. It is amongst the countries with lowest per capita carbon footprints.

In 2017, Petroleum had a share of 44% in the Primary Energy basket, followed by Bio-mass (36%), Coal (11%) and Hydro & New Renewables (9%). Source-wise share of Primary Energy in 2017 was as follows:

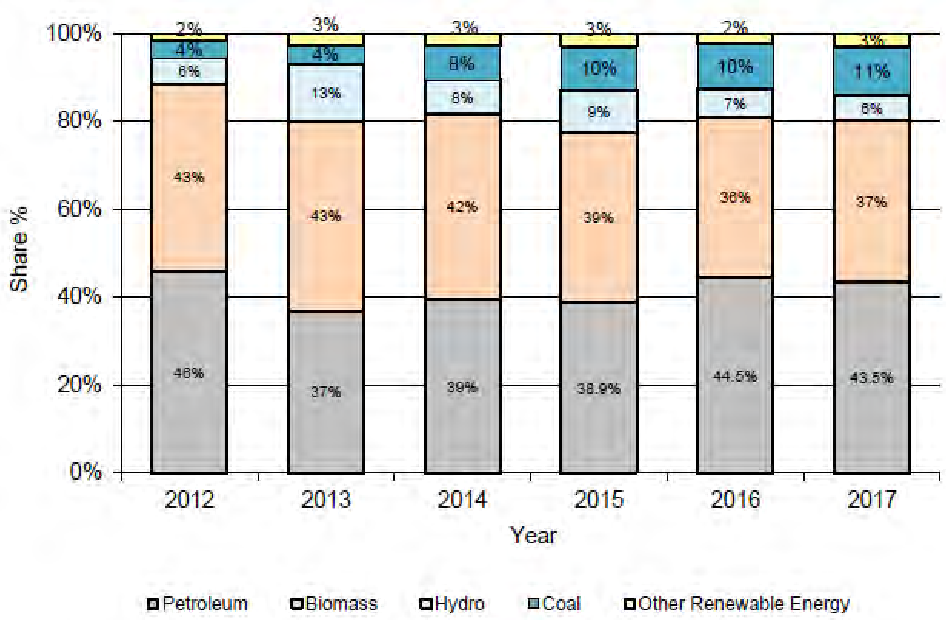
Table-3.1.1: Share of sources in Primary Energy in 2017 in Sri Lanka

Source	Share (in %)
Bio Mass	36
Petroleum	44
Coal	11
Major Hydro	6
New Renewables Energy	3

(Source: Sri Lanka Sustainable Energy Authority, IRADE)

The share of fossil fuels, coal and petroleum products, have increased over the past few years. The trend of share of different sources in the Primary Energy requirements of Sri Lanka are as follows:

Fig-3.1.2: Source-wise share of Primary Energy of Sri Lanka
(Source: Sri Lanka Sustainable Energy Authority)



About 24.3 % of Primary Energy consumption is consumed in Industry, 36.2% in Transportation and 39.6% in Household, Commercial & other sectors.

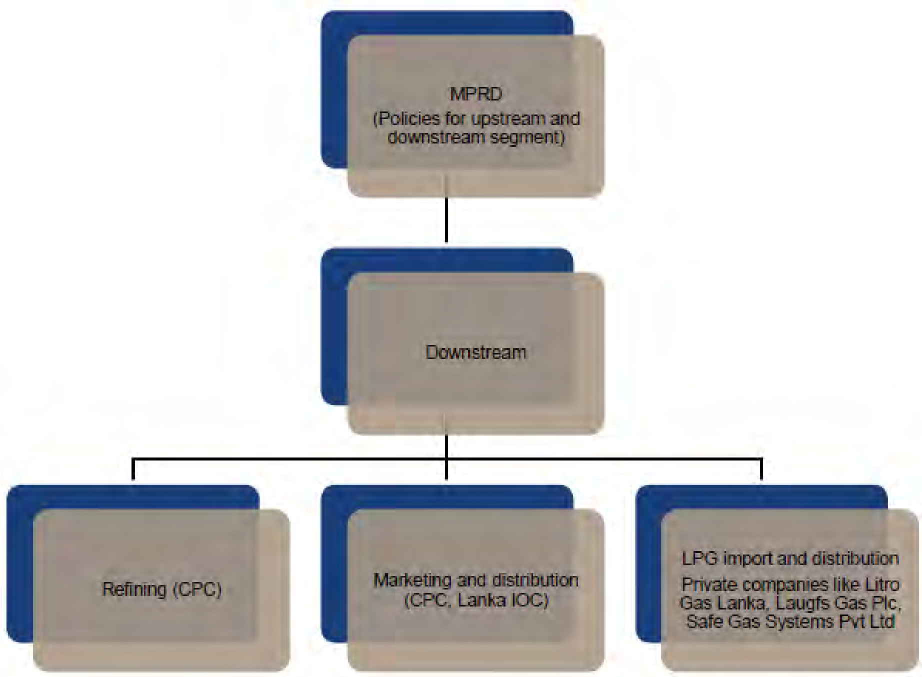
3.2 Organogram of the Oil and Gas sector.

The entire upstream and downstream sectors are regulated by the Sri Lanka Government under the Ministry of Petroleum and Resources Development (MPRD). The Petroleum Regulatory Development Secretariat (PRDS) was established under the Petroleum Resources Act No 26 of 2003. PRDS operates under the Ministry of Petroleum and Resources Development and is responsible for all the functions for the government in promoting the exploitation of the Petroleum Resources.

The midstream sector, comprising procurement of crude and oil refining, is looked after by the Ceylon Petroleum Corporation (CPC or Ceypetco), which operates under MPRD. Till 2002, the downstream distribution and sales of refined petroleum products was under the operation of Ceypetco. In 2003, a new legislation (Petroleum Products Special Provisions Act No 33 of 2003) paved way for unbundling of the downstream and paved way for the entry of private and other entities. As of now, CPC, along with Lanka IOC (an Indian NOC) and also some other private entities, are in the distribution and sales of refined petroleum products. Litro Gas Lanka is the state-owned LPG supply and distribution company. The main private entities are LAUGFS Gas Plc, Safe Gas Systems.

The organogram of the Hydrocarbon sector is as follows:

Fig-3.2.1: An Organogram of Sri Lanka midstream and downstream Sector



In addition to the above, Ceylon Petroleum Storage Terminals Ltd (CPSTL) operate the storage terminals in Sri Lanka. The CPSTL operates with joint participation of CPC and Lanka IOC.

3.3 Regulatory Environment and Government Policies

3.3.1 Upstream Sector

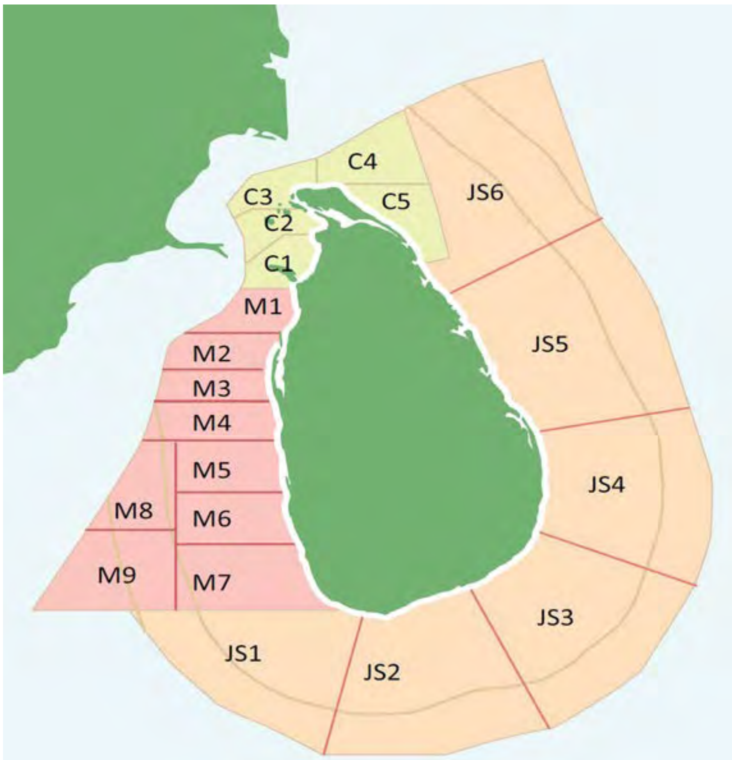
Sri Lanka lacks in any production of domestic hydrocarbon resources, coal, gas or oil. It can be seen in Fig 3.3.1 above that Petroleum has the highest share in the primary energy basket. It has three sedimentary basins, Mannar, Cauvery and Lanka basins.

The CPC was the government anointed nodal agency for the exploration programs. Exploration began in late sixties. In early seventies, Russia carried out extensive geological surveys and spudded three exploratory wells without any significant commercial value. In 1975, Russia relinquished its interest.

In early eighties, encouraged by the PH-9 discovery in Cauvery Basin by ONGC, about 30 kms north of its territorial boundary with India, further exploration programmes were undertaken. The exploration activities continued for two more decades with more exploratory data being collected.

While Sri Lanka continued to pursue its exploration program, not much headway could be made till 2008. Meanwhile, the Petroleum Regulatory Development Secretariat (PRDS) was established under the Petroleum Resources Act No 26 of 2003. PRDS operates under the Ministry of Petroleum and Resources Development and is responsible for all the functions for the government in promoting the exploitation of the Petroleum Resources. The PRDS adopted a more focussed approach for exploitation of petroleum resources. In 2007, Sri Lanka reorganized its exploratory data, and demarcated its blocks for launching a comprehensive E&P program. The figure 3.3.1 below illustrate the blocks in its three basins:

Fig-3.3.1: The Basins and Blocks of Sri Lanka



(Source:Energy Balance Report by Sri Lanka Sustainable Energy Authority)

Key activities undertaken in recent years by PRDS for exploitation of its basins are as follows:

- In 2007, PRDS launched an ambitious plan for Exploration & Production from three blocks in Mannar basin and invited foreign participation by IOCs. Bids were received for all the three blocks. However, the bids of two blocks were not adequate and bids of only one block were reviewed. The bidders for this block included Cairns India, Niko Resources and ONGC. In 2008, Cairns India (now Cairns Lanka) was awarded this block.

- In 2012, Cairns Lanka made two discoveries of gas in this block in Mannar Basin, the 'Barracuda' and 'Dorado' reservoirs. However, inspite of drilling two wells, it did not find the reserves to be commercially exploitable. In 2015, Cairns Lanka relinquished these blocks.

- PRDS launched a program for developing a common repository with quality exploration data in order to attract exploration companies. In 2016, Sri Lanka signed a Joint Exploration Agreement with Total SA for collecting more exploratory and seismic data in Blocks JS-5 & JS-6 off the eastern coast. In 2018, acquisition of 2D seismic data across 5,000 kms was collected and is being analysed. In 2019, this agreement was renewed.

- In 2017, Sri Lanka tied up with IHS Global and launched a marketing campaign for persuading International Oil Companies to participate in exploration and production of oil & gas. In 2018, Sri Lanka entered in the Umbrella Multi-client Data Acquisition Project with Schlumberger for collecting 2 Dimensional & 3 Dimensional Seismic data in the eastern and western off-shore areas. This would help to build up the data repository for offering the blocks for interpretation and exploitation Data acquision has been carried out in the following areas:

Cauvery Basin: 250 LKm
Lanka Basin: 500 LKm
Mannar Basin: 2,500 LKm

- In 2019, Sri Lanka signed an Agreement with Bell Geospace for collecting Multi Client data Airborne Gravity, Gravity Gradiometry and Magnetic Surveys of its coastline to reinforce its data depository and offer more data for interpretation. Encouraged by the data interpretation, Sri Lanka claims that the Mannar Basin itself holds significant reserves. These two discoveries in the M-2 Block are estimated to have the 'Gas Initially in Place' (GIIP) reserves in excess of 2 tcf.
- In 2019, with updated exploratory and seismic data, Sri Lanka invited bids for M-2 and C-1 Blocks and the same are under approval. Once finalized, development and gas production can be expected in 3-4 years after award.

The PRDS claims to posses about 18,000 kms of Magnetic and Gravity data and about 19,000 kms of 2D Seismic data in its depository.

3.3.2 Mid Stream and Downstream

Mid Stream and Downstream

CPC operates the Sapugaskanda Refinery, the only refinery in Sri Lanka. The capacity of the refinery is 50,000 bbl/day. The refinery was built in 1969 and was designed with the specifications for processing light crude oil from Iran. The recent sanctions on Iran has compelled Sri Lanka to source crude from the Abu Dhabi, UAE (Murban, Das & Upper Zakum crude) and Oman (Oman crude). The technical specifications of the processing units are not suitable to other crude oils. As compared to the light Iranian Crude, processing of these heavy crude oils has reduced the efficiency and throughput of the refined products. The annual production has come down by at least 20-25%.

The refinery provided the entire requirement of Sri Lanka in the 70s. In the following decades, the demand increased and Sri Lanka resrted to imports of refined products. Further, processing the Abu Dhabi and Oman crude oils has affected domestic production of refined petroleum products and has led to higher dependence on imports. In 2017, the Sapukaskanda refinery produced only about 1.8 Million Tons and could meet only about 32% of the country's demand.

The government is planning for refurbishment of the Sapugaskanda Refinery, both in terms of capacity and quality of refined petroleum products. The Ministry of Petroleum / CPC are drafting the specifications for a transparent tendering process. The capacity is likely to be doubled to 100,000 barrels per day. The likely investment is about USD 2 Billions. The National Energy Policy and Strategies has earmarked the expansion as crucial for energy security. CPC and MPRD have been entrusted to finalize the Feasibility studies by 2020.

Oil Storage and Terminals

The other midstream player is the Ceylon Petroleum Storage Terminals Ltd (CPSTL), whuch owns and operates the oil import terminals and storage facilities. It offeres these facilities as 'common user facilities' (CUF) to the supply and distribution companies. The CPSTL operates with joint participation of CPC and Lanka IOC. Its terminals have a total capacity of about 1.2 Million Tons, enough for about 90-100 days of consumption. The National Energy Policy 2018 stipulates that every downstream petroleum supply and distribution company should maintain at least 30 days of stock.

Petroleum supply and distribution

Till 1960, the Petroleum sector was an oligopoly comproising of several IOCs. In 1961, vide The Ceylon Petroleum Corporation Act No 28 of 1961, the entire petroleum sector including imports and domestic supply and distribution came under Ceylon Petroleum Corporation (CPC).

In 2003, a new legislation (Petroleum Products Special Provisions Act No 33 of 2002) paved way for unbundling of the downstream and paved way for the entry of private and other entities. As of now, CPC along with Lanka IOC (an Indian NOC) and also some other private entities are in the distribution and sales of refined petroleum products. Both the companies independently manage their supply chain management.

The Petroleum sale for retail is done from the storage facilities at Muthurajawela, Kolonnawa, Sapugaskanda Distribution facility and China Bay storage facility. There are thirteen regional depots for retail distribution.

LPG

The Sapugaskanda refinery produces some LPG for domestic consumers. The refinery's LPG is supplied to bottling plants of private distributors by road tankers for further distribution. However, the major LPG quantities are imported by the Litro Gas Lanka, the state-owned LPG supply and distribution company. It is imported at the Colombo Port and at its Muthurajawela facilities using a conventional buoy mooring system. The other private entity in LPG supply and distribution is LAUGFS Gas Plc and Safe Gas Systems.

Bio-mass: Sri Lanka is dependent on Biomass for meeting its 37% of its Primary Energy requirement. Its forest cover, which was 43% 1948, had reduced to just 29% in 2010 including all plantations for tea, coffee & other crops.

Sri Lanka is one of the lowest CO2 producing countries. Its per capita CO2 production is about 4 times less than India. The nation has submitted its INDCs in Paris COP (2015).. The expansion of its forest cover from 29% to 32% by 2030 is a part of its energy policies and commitment to achieve the targets of its NDCs. The replacement of firewood by LPG is an initiative towards its commitments.

3.3.3 Petroleum Pricing & Subsidies

Petroleum prices are under government control and are periodically revised . These are discussed in the sector review of the petroleum sector in section 3.5.2.

3.4 Gas Reserves & Policy Initiatives for Gas

A) Gas Reserves:

Sri Lanka are yet to establish proven gas reserves. However, as mentioned at Para 3.3, Cairns Lanka made two discoveries of gas in 2012 in the Mannar Basin, the 'Barracuda' and 'Dorado' reservoirs. However, inspite of drilling two wells, it did not find the reserves to be commercially exploitable and in 2015, Cairns Lanka relinquished these blocks.

As also enumerated above at 3.3.1, to intensify its gas exploration, , Sri Lanka tied up with Schlumberger in an Umbrella Multi-client Data Acquisition Project for collecting 2D & 3D Seismic data in the eastern and western off-shore areas between 2017 and 2019. It also entered in an agreement with Geospace for acquisition of Multi Client data Airborne Gravity, Gravity Gradiometry and Magnetic Surveys of its coastline. Data acquisition has been carried out in all the three basins.

The objective was to collect extensive data and create a comprehensive data repository for offering the blocks for interpretation and exploitation. Based on the data interpretation, Sri Lanka claims that the Mannar Basin itself holds significant reserves well over 2 tcf. The 'Dorado' reservoir has estimated potential of 300 bcf and 'Burracado' reservoir can produce upto 1.8 tcf. The Dorado gas fields once developed can produce upto 70 mcfd for 9 years, while the Burracado fields have potential for about 210 mcfd for 22 years.

The key challenges being faced by PRDS for attracting investors are lack of local infrastructure for consumption, export facilities, preparation of flexible contracts for Production / Revenue sharing and project execution in the ecologically sensitive shallow Off-shore areas, which provide rich export revenues from fishing / shrimp farms.

(B) Policy initiatives for increasing Gas in the energy basket

(i) National Energy Policy & Strategies of Sri Lanka: In 2019,'National Energy Policy & Strategies' has been notified by the SriLanka government via gazette notification. The three key aims of the policy are Energy Security, Energy Sustainability and Equity. The development of its petroleum (and gas) resources and pipeline infrastructure are included as the fossil fuel of preference to help Sr Lanka achieve the energy security. The Policy has outlined actionable targets for PRDS & CPC for the development of gas reserves and downstream pipelines. Some of the key result-oriented targets are:

- PRDS and SEA to compile a short-term and medium-term plan for the Petroleum and Gas sector by 2020.
- PRDS to compile an inventory of all resources and publish it by 2020. It shall carry out Air borne gravity / magnetic data by end 2019 and collect selected 2D / 3D seismic data on Mannar and Cauvery basins by 2022.
- PRDS along with SEA to complete a feasibility report for use of gas, RE-based Hydrogen and Gas-to-Liquid in all sectors by 2020
- MoPRD to introduce a legislation for Regulatory Mechanisms for the Upstream and Downstream sectors by 2020.
- A joint committee of CPC and CEB to identify BYB 2020 the land required for laying of the gas pipelines upto 2030.

(ii) National Policy on Natural Gas: The PRDS has drafted a National Policy on Natural Gas (NPNG). The salient features of this Policy are:

- Objective is to increase gas utilization for economic, social and environmental benefits,
- Policy to encompass power, industrial, transportation, household and commercial segments of the Sri Lanka economy.
- To facilitate regulatory and institutional framework for developing the gas economy.
- To support and help Srilanka to meet its Committed and Conditional NDCs and Sustainable Development Goals (SDG) for combating the 'Climate Change'.
- To facilitate development of infrastructure and logistics to enable natural gas reach one-thirds of fossil fuel consumption.
- To formulate enabling policies on taxes, duties and pricing.
- CPC shall be the Single Credible Entity on behalf of the government for sourcing of LNG, implementation of all projects and agreements and for providing Technical and Institutional assistance to NPNG.
- The Public Utilities Commission of Sri Lanka (PUCSL) shall be the Regulator for all Midstream and Downstream policy matters while PRDS shall continue to regulate the Upstream policies and initiatives for exploration and production.
- A separate National Gas Company is proposed for taking over the LNG business and gas distribution & marketing. The National Gas Company would also provide Technical and Institutional assistance to NPNG.
- A Gas Utilization Master Plan (GUMP) to be prepared on approval by the Cabinet in a year's time from the approval of the policy.

The Gas Utilization Master Plan (GUMP) proposed in the NPNG is expected to identify gas utilization in all the sectors (including Power, Transport, households, industry as well as for bunkering, export and re-export for trading puposes) in a five-year planning horizon. The GUMP is expected to be of significant help in forecasting the gas requirement for Sri Lanka

It can be seen that the government is quite keen to include gas as a preferred fossil fuel option for meeting its energy needs.

(iii) Government consent for LNG Terminal and Gas-based power plants:

The Sri Lankan government has been considering natural gas based Combined cycle plants on a bilateral Government – to- Government basis. In Jan 2020, the Sri Lanka Cabinet has approved a proposal to move ahead with 300 MW LNG fuelled Combined Cycle plant with Govt of India and Japan at Kerawalpitiya. It has approved utilizing the financing from Asian Development Bank for accelerating the construction of a 300 MW gas based plant at Kerawalpitiya. Under Bilateral arrangements, it is in discussions with Petronet (India) alongwith Mitsubishi (Japan) and Sojitz (Sri Lanka) for installing FSRU of about 0.3 to 0.8 MTPA capacity. The LTGEP 2020-2039 Draft envisages conversion of the 172 MW diesel-fuelled Sojitz Kelanitissa Combined Cycle plant to Gas fuel. It is also discussing with Kogas (South Korea) for another FSRU.

iv) Sri Lanka's initiative for fostering LNG trading:

In August 2020, an agreement has been entered between the Board of Investment of Sri Lanka with Pearl Energy (Saudi Arabia) in August 2020 for a Floating Storage LNG Trading facility at Hambantota port. With this, Sri Lanka aims to use its strategic position as a LNG bunkering and trans-shipment hub and reap benefits of the first mover advantage for fostering regional trade in LNG within BBINS in South Asia.

v) Emergence of new gas-based industry, particularly fertilizer for intra-region requirement:

Sri Lanka proposes to coordinate with countries within BBINS and also beyond for new gas-based fertilizers at competitive prices.

3.5 Analysis of the key energy sectors

Sri Lanka Power Sector

Sri Lanka Power Sector snapshot Planning of the power sector is under the control of Ministry of Power & Energy. In 1969, the Ceylon Electricity Board Act -78 of 1969 led to the formation of Ceylon Electricity Board (CEB). Presently, CEB is the main stakeholder in the Generation, Transmission and Distribution of Electricity. In the nineties, the power sector was opened for participation by private sector. In 1992, private participation was invited by Expression of Interest, discussion of the offer and issuance of the LoI. In 1996, the RFP/ RFQ mode was introduced and some private generators participated and were awarded the LoI. In 2002, the Public Utilities Commission of Sri Lanka (PUCSL) Act No 35 of 2002 was passed following which, the PUCSL commenced functioning as the key regulator of the Energy Sector. At present, in power generation, in addition to CEB, there are some IPPs and SPP (Small Power Plants) which own and operate Hydro, Thermal and Renewables. Transmission is still fully owned and managed by CEB. In distribution, Lanka Electric Company (Pvt) Ltd (LECO), with majority stake of CEB along with CEB's subsidiaries, also operates a small share of retail power supply.

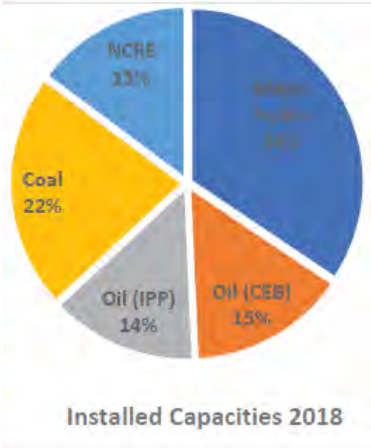
The forecast of electricity's demand and planning the generation-mix of the capacity addition etc in the electricity sector is carried out by the Generation and Transmission Planning Branch of the CEB. It considers all prevailing policies and guidelines to draw the Long-Term Generation Expansion Plan (LTGEP) in different scenarios of growth. It also draws the Least Cost LTGEP, which is reviewed and updated periodically.

Existing Generation Sources

As per the Annual Performance Report 2019 of CEB, Sri Lanka's installed capacity at the end of 2018 was 4063 MW. CEB claims that 100% of the demand was met. The maximum Peak Demand in 2018 was 2,260 MW and Energy generated was 15,925 GWHrs. The source wise installed capacity and its share is illustrated as in the Figure 3.5.2 below:

Fig-3.5.2: Source-wise Capacity and their share.

Source		Capacity (MW)	No. of Power Plants
Major Hydro		1,399	17
Thermal			
	Oil (CEB)	604	7
	Oil (IPP)	560	4
	Coal	900	1
Renewable (NCRE)			
	Mini Hydro	394	190
	Wind	129	15
	Solar	51.4	8
	Dendro & Biomass	26	11
Total		4,063	254

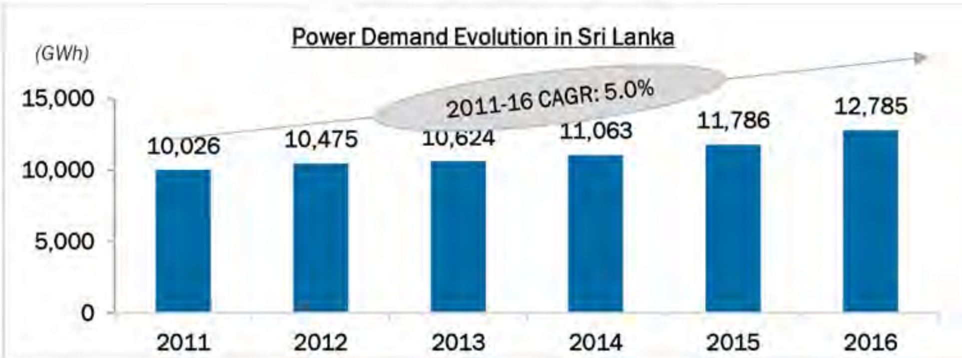


(Source: Sri Lanka Power Performance Report 2018, Min of Power,Govt of SL)

As at end of 2018, the country had 145 MW of roof-top Solar, with 77.6 MW added in 2018 alone. Sri Lanka plans to cover one million households in next 10 years under this programme. The target is to install a capacity of 1,000 MW of roof-top solar by 2025.

Past Growth: The power demand has grown from 10,026 GWHr to 12,785 GWHrs between 2011 and 2016 in Sri Lanka, at a CAGR of 5.0% from 2011 a s in the figure below:

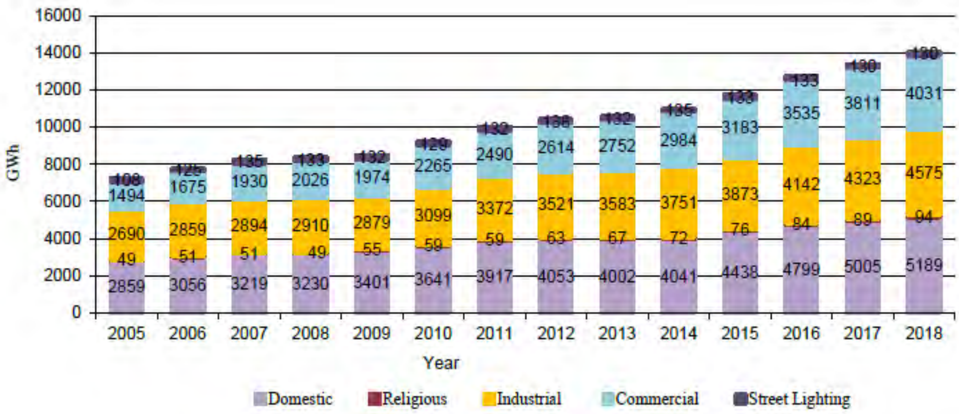
Fig-3.5.3: Evolution of Demand from 2011 to 2016



(Source: World Bank Report 2019 Sri Lanka Energy Infra SAP)

Sector-wise Consumption: In 2018, the domestic consumers have about 37% share in the power consumption followed by Industrial (33%) and Commercial (29%). Over the years the demand in Commercial sector has grown more than other sectors as indicated in the figure below:

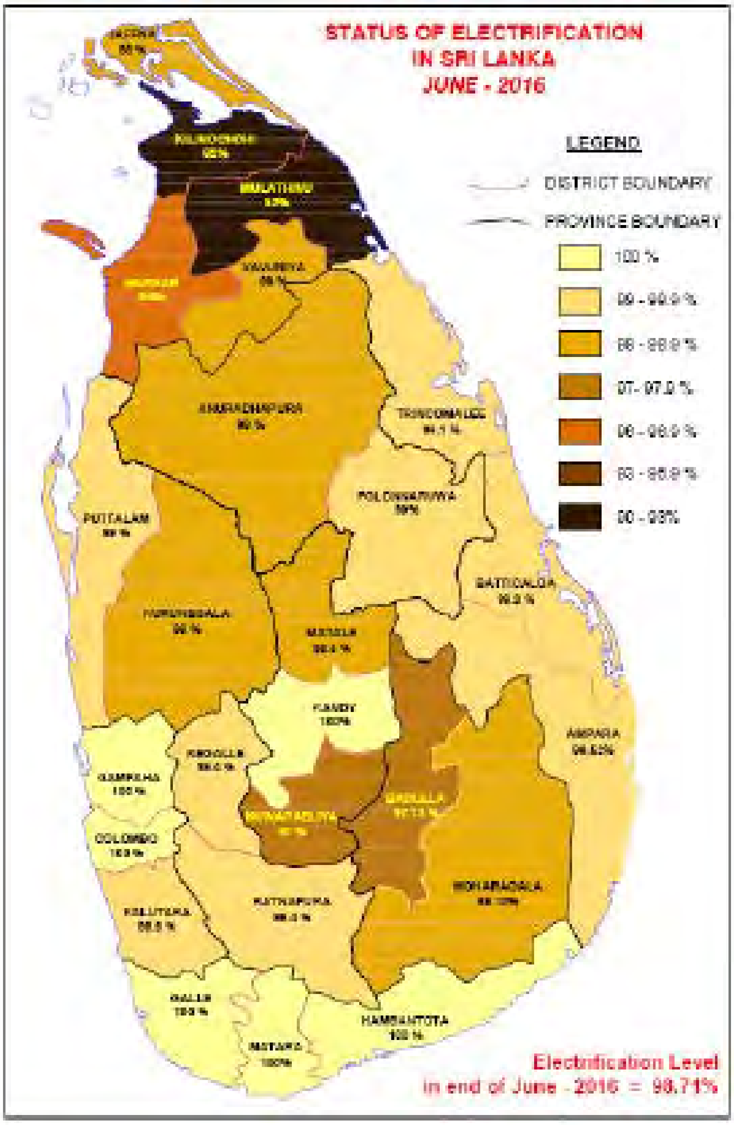
Fig-3.5.4: Share of Sectors in Power Consumption



(Source: LT GEP 2020-2039 Draft)

Level of Electrification: Sri Lanka is the first South Asian country to achieve 100% access of grid-connected or off-grid connected electricity for all households. It has achieved electrification of 99% by 2018. As LTGEP 2020-39 (Draft), the average electrification was 98.61% as in 2016. The region in the North, (in dark brown) as in the figure 3.5.5 below, lacked penetration and are expected to be fully covered by 2020.

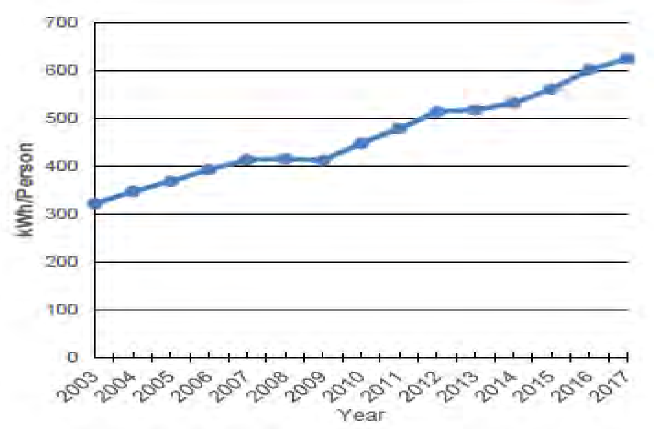
Fig-3.5.5: Electrification in Sri Lanka



(Ref LTGEP 2020-39 Draft)

The per capita power consumption is growing at over 5% per annum as in the figure below:

Fig-3.5.6: Per Capita Power Consumption 2003 to 2017

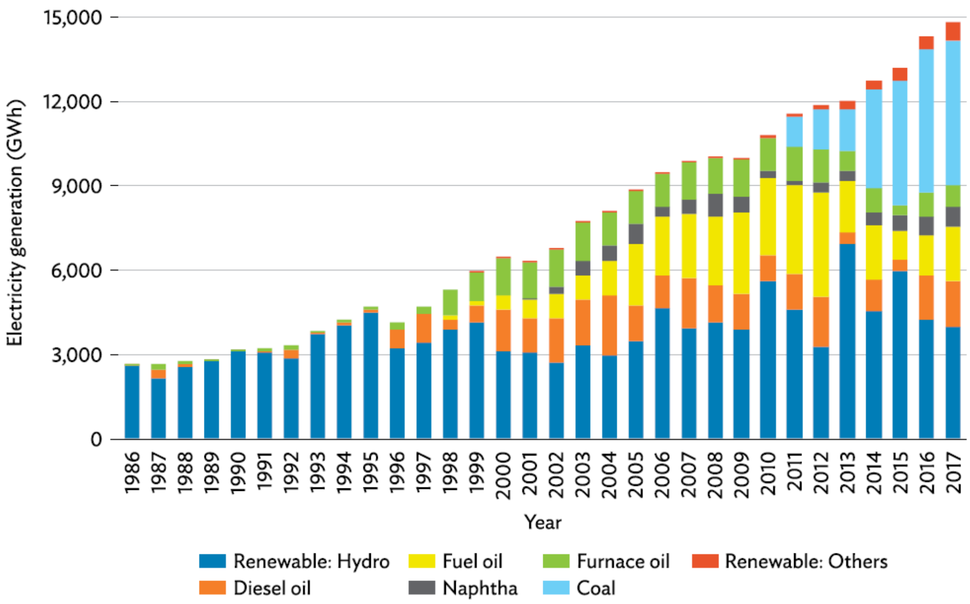


(Source LTGEP 2020-2039 Draft)

Generation Mix

From 1912 to the early nineties, Sri Lanka exploited its Hydro power resources to generate electricity. As the exploitation of its Hydro resources saturated, it shifted to Oil-based (Diesel, Furnace Oil, Naphtha) generation capacity. From 2010 -2011, it has added coal-based and renewable in its generation mix as shown in the Fig 3.5.7 below:

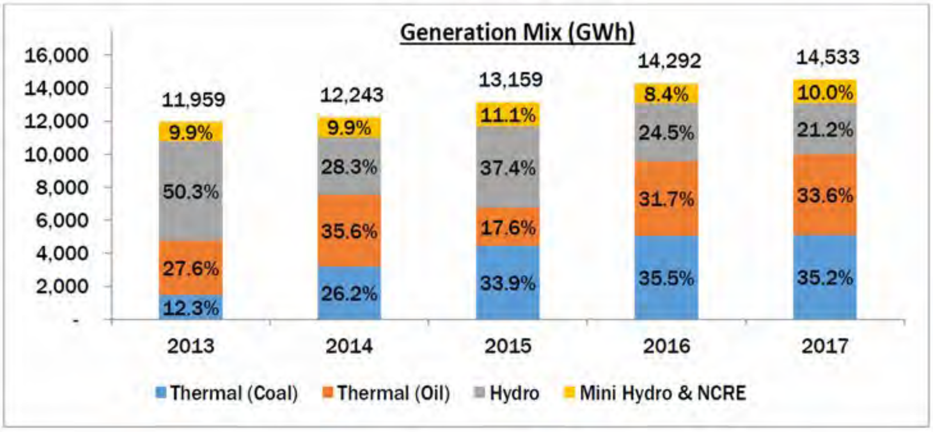
Fig-3.5.7: Generation Mix (1986 – 2017)



(Source ADB Sector Assessment 2019, SLSEA Energy Balance 2017)

The thermal sector, with installed capacity of about 36%, had the largest share of about 69% n the energy generated in 2018. Hydro's share declined due to adverse rains and was only about 22% as compared to 50% share in 2013. The rest 10% is from small hydro and Other Renewables.

Fig-3.5.8: Source-wise generation in Sri Lanka



(Source: World Bank Report 2019 Sri Lanka Energy Infra SAP)

Fuels for Power Generation:

Sri Lanka's dependence has grown on fossil fuels to meet the power demand. In 2011, the first 300 MW Unit of the imported coal-based 900 MW plant was commissioned at Lakvijaya Power Plant at Norochcholai in 2011. The growth of fossil fuel consumption is as indicated in the table below:

Table-3.5.2: Thermal Plant Efficiencies of existing plants

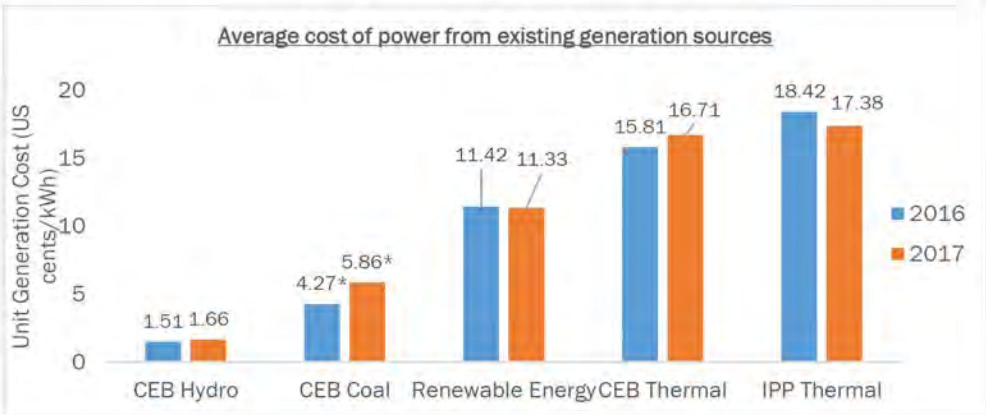
Power Plant Efficiencies	2005	2010	2014	2015	2016	2017
CEB						
Steam, Coal	-	-	38.6%	35.5%	37.8%	36.7%
Steam, Diesel	-	-	19.8%	31.4%	20.2%	19.9%
Diesel Engine, Residual Oil	39.5%	39.5%	39.4%	39.4%	39.5%	39.3%
Diesel Engine, Fuel Oil	-	-	39.8%	40.0%	40.3%	40.2%
Diesel Engine, Diesel	21.9%	29.8%	28.1%	31.9%	29.5%	28.7%
Gas Turbines, Diesel Oil	26.7%	23.4%	26.1%	25.8%	26.1%	25.8%
Combined Cycle, Diesel Oil	42.4%	40.9%	39.9%	42.5%	42.2%	38.6%
Combined Cycle, Naphtha	41.5%	33.7%	38.8%	41.3%	41.2%	38.2%
CEB Gross Thermal Generation (Gcal)	1,859,282	1,199,040	4,531,430	4,750,977	6,387,301	6,637,076
CEB Fuel Energy Input (Gcal)	4,909,253	3,198,724	11,907,089	13,074,230	16,894,212	18,157,111
CEB Power Plant Efficiency	**37.9%**	**37.5%**	**38.1%**	**36.3%**	**37.8%**	**36.6%**
IPP						
Diesel Engine, Residual Oil	39.1%	39.3%	38.2%	38.6%	38.7%	36.7%
Diesel Engine, Fuel Oil	39.2%	40.2%	39.8%	40.2%	38.4%	45.9%
Diesel Engine, Diesel Oil	40.8%	33.4%	-	-		36.2%
Combined Cycle, Diesel Oil	46.8%	44.4%	38.2%	44.7%	43.7%	41.8%
Combined Cycle, Fuel Oil (LSFO 180 cst)	-	39.9%	41.0%	38.4%	36.3%	41.0%
Combined Cycle, Fuel Oil (HSFO 180 cst)	-	-	-	-	-	24.0%
IPP Net Thermal Generation (Gcal)	2,732,531	2,684,904	1,803,069	516,533	1,394,647	1,167,263
IPP Fuel Energy Input (Gcal)	6,796,878	6,639,385	4,459,202	1,237,795	3,324,129	2,769,632
IPP Power Plant Efficiency	**40.2%**	**40.4%**	**40.4%**	**41.7%**	**42.0%**	**42.1%**

(Source: LTGEP 2020-2039 Draft)

Energy Costs

The energy cost of generation depends on the efficiency of the plants, heating value of fuel and the landed price of fuel. Sri Lanka imports Fuel oil (Diesel & HFO) as well as coal for power generation. The energy cost of NRE is significantly higher than the coal-based generation. The costs of other thermal energy based (Diesel and HFO based power plants) are about 30% higher than NRE. A comparison of the energy charges for 2016 & 2017 is as indicated in figure 3.5.9 below:

Fig-3.5.9: Energy Charges (Excluding Financing Costs) from different sources in 2016 & 2017



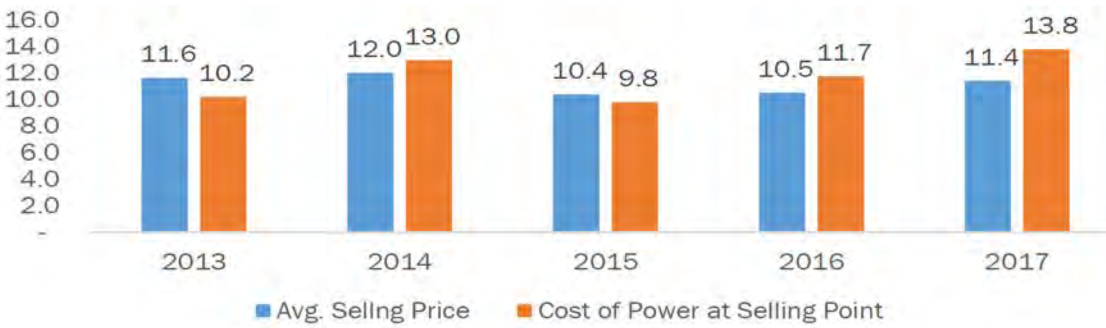
*Does not include financing, environmental / health costs

Source: World Bank Report 2019 Sri Lanka Energy Infra SAP

Electricity Tariffs:

The electricity tariffs have a direct impact on the GDP growth, and have been kept low by the Government. The cost of power is higher than end-user price. As per a recent news report, the losses of CEB were a staggering Rs 85 Billions in 2019. An analysis by the World Bank of the unit cost of power and the selling price is reproduced in figure 3.5.10 as below:

Fig-3.5.10: Average Cost of Power and Selling Price



(Source: World Bank Report 2019: Sri Lanka Energy InfraSAP)

The impact of subsidized power is reflected in the financial performance of CEB. As per the SLSEA report, against assets of 723 Bn SL Rupees, the return was negative, i.e., (-) 4.3% in 2018 . The net loss was a little over 30 Billion Rs at the end of 2018.

Capacity Addition Plans

The Generation Planning Division of CEB, Sri Lanka prepares a 20 Year Long Term Generation Expansion Plan (LTGEP) which is approved by Public Utilities Commission of Sri Lanka (PUSCL). The LTGEP is reviewed and updated every two/three years. The LTGEP -2018 to 2037 was prepared and approved in June 2018. Recently, the LTGEP 2020-2039 Draft has been prepared and web hosted by CEB for consultations.

The LTGEP takes into consideration the following key factors ;

- The Cabinet approved Energy mix policy of Sri Lanka. This policy reiterates commitment of at least 30% generation capacity by New Renewable Energy (other than Hydro) by 2030. It has approved that to meet energy security, two thirds of electricity generation to be met by firm energy capacity comprising of LNG, Coal, Fossil Fuels and Large Hydro. It has recommended that firm energy capacity mix shall comprise of 30% from LNG, 30% from Coal, 25% from Large Hydro, and remaining 15% from Furnace Oil and NCRE. It also recommended adoption of Renewable Energy with Storage so as to achieve self-sufficiency by 2050. This Energy-Mix policy is a key planning input for CEB and PUCSL.
- The power generation capacity under implementation
- Historical data of the energy costs, fuel costs etc.
- Demand and Energy forecast by the Distribution and Transmission wings.
- The Reliability Criteria
- Efficiency measures in the Demand Side Management
- Sri Lanka's commitments / INDC in COP 21, 22 & 24.
- Data on the Capital and Variable costs of the candidate plants for analysis and selection

For Medium Term Demand and Energy Forecast (2020-2024), the LTGEP has utilised the time series duly corrected by inputs from its distribution planning team. For Long-term forecast, it has utilised econometric modelling based on its three key consumers, i.e., Domestic, Industrial & Commercial. For plotting the regression for the respective segments, it has utilised the GDP Growth for Domestic, 'Industrial GDP Growth' rates for Industrial and 'Service Sector GDP growth rates' for the Commercial sector. It has also used the IAEA's latest software MAED (Model for Analysis of Energy Demand) for comparing the Medium-Term and Long-Term as per its forecasts.

For selection of plants for its energy mix, it has used a number of established software programs like SDDP for Long-term Hydro-Thermal optimization, , WASP-IV (IAEA), NCP & OPTGEN (Brazil) for investment decisions with variables, and MESSAGE (Energy Supply Strategy and their General Environment Impact), using considerable data on capital and variable costs for the candidate plants, achievable efficiencies at different load factors, fuel price escalations, and constraints for the generation, transmission and distribution.

Exploring LNG-based power plants: India, the nearest neighbour of Sri Lanka is deficient in domestic gas supplies, and in fact is an importer of LNG. Therefore, feasibility of laying of a sub-sea gas pipeline from Indian mainland would not only be economically expensive, but futile as well, and it was ruled out. Hence, procuring LNG is more feasible option. In this regard, four studies had been carried out earlier, as explained below,

- July 2002: Sri Lanka Electric Power Technology Assessment Report (July 2002)
- June 2003: Sri Lanka Natural Gas Options Study by USAID-SARI / Energy Program
- 2010: Phase-I of JICA-funded 'Study for Energy Diversification Enhancement by Introducing LNG Operated Power Option in Sri Lanka'
- Phase –II of the above study sponsored by JICA.

The first two studies concluded that the potential LNG demand of Sri Lanka was mainly from the power sector, and too small for installing the capital-intensive LNG Receiving infrastructure. The third study by JICA concluded that following the gas pricing models as by India in 2008-09, LNG too could be competitive with coal.

While carrying out the detailed analysis of the generation costs, the thumbnail capital costs for Terminal-based and FSRU-based RLNG plants were taken afresh, Term LNG prices were taken as 12.5% slope of Crude parity and a 2 $/mmbtu overheads were added to work out the costs of the LNG supplies.

Forecast for Capacity Additions and Fuel Requirement for Thermal Generation:

The capacity addition in the Base Case of the LTGEP 2020-2039 Draft, equivalent to the Base Case of LTGEP 2018-37, are as indicated in the table 3.5.3 below:

Table-3.5.3: The source-wise addition of Generating Capacity

Type of Plant	2020-2024 (MW)	2025-2029 (MW)	2030-2034 (MW)	2035-2039 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	227	-	-	-	227	3%
Pumped Hydro	-	400	200	-	600	6%
Gas Turbines	105	-	-	-	105	1%
Coal	900	900	900	900	3600	36%
NG CCY	600	0	600	600	1800	18%
Reciprocating Engine	300*	(-200)	-	-	100	1%
ORE	910	750	850	915	3425	35%
Total	**3042**	**1850**	**2550**	**2415**	**9857**	**100.00%**

* This figure represents the net capacity addition for the period.

(Source: LTGEP 2020-2039 Draft)

Demand Outlook for Fuel Consumption in Base Case

As per the growth of source-wise generation, the Annual Fuel requirement for the thermal plants has been worked out year-wise in the LTGEP 2020-2039 Draft . The base case requirement of fossil fuels is as in the Table 3.5.4 below:

Table-3.5.4: Annual Fuel Requirement in Base Case Energy Demand

Fuel	Unit	2020	2025	2030	2035	2039
Oils	in 1000 MT	1588	88	89	93	69
Coal	Million MT	1.5	2.8	3.6	4.7	5.9
LNG	Million MT	0	1.0	1.5	1.8	2.2
Dendro	Million MT	0.6	0.9	1.2	1.5	1.8

(Source LTGEP 2020-2039 Draft /IRADe)

Amongst the reference and the base case scenarios, Sri Lanka has also considered Import of Power from India as enumerated in the Para below:

Import from India: Interconnecting transmission systems.

The shortest geographical distance between the India and Sri Lanka mainland is less than 30 kms, from Dhanushkodi in India to Talaimannar in Sri Lanka, across the Gulf of Mannar. In 2002, a study by USAID was carried out for feasibility for a transmission link with India. Connectivity with India's transmission networks provides Sri Lanka an opportunity for import of cheaper power during peak load, stabilising base loads and taking benefits from India's Power Exchanges for reduction in operational costs.

As per the analysis in the World Bank Report, in 2017, PUCSL estimated that the power generation cost on coal in Sri Lanka would be about 11 cents/kwhr with the financing cost at LIBOR + 4.5%. In 2009, Sri Lanka had secured a concessional loan from China government for the 900 MW coal based plant an average all-in cost of of 2.7% and if financing can be achieved at such rates, the World Bank estimates the generation cost on coal to be in the range of 8 to 9 cents/kwhr.

Considering that even though the coal prices witness volatility, the transmission connectivity and import from India are competitive against the cost of generation from coal based plants (inclusive of the financing charges and variable charges). It certainly makes sense as prices in Short-term, Mid-term and Real Time Markets (RTM) have come down considerably and it would be economical to tie up power from Indian Suppliers on the similar model as that used for bilateral supply of electricityby India to Bangladesh.

Pertinent to mention that the estimated cost of generation on coal excludes the environmental, health and carbon costs.

As per LTGEP 2020-2039 Draft, the transmission line connectivity has been again discussed with India in 2017 onwards. The HVDC Station on Sri Lanka side has been shifted from Anuradhapura to New Habarana. A third Alternative of Laying a Sub-sea cable from Dhanushkodi to Thirukettiswaram has also been discussed and once the option is agreed between the two sides, the same can be taken up for feasibility studies.

First phase is 500 MW and second phase is anpother 500 MW.

Battery Storage

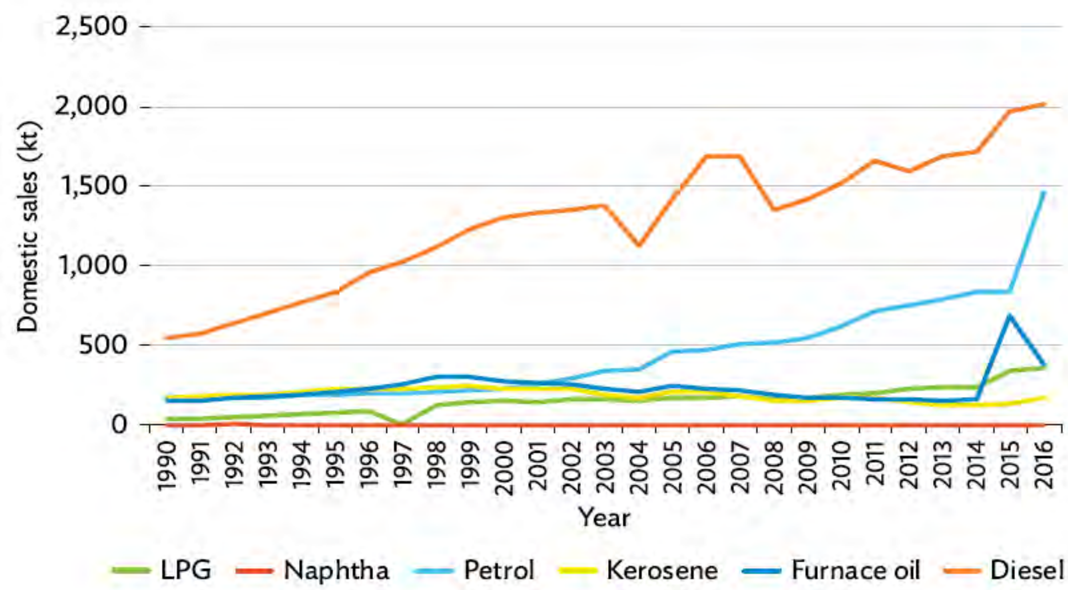
The Cabinet approved Energy Mix policy of Sri Lanka has proposed to explore adoption of Renewable Energy with Storage so as to achieve self-sufficiency by 2050. The The Base Case scenario of the Draft LTGEP-2020-39 has envisaged Battery Storage of 50 MW in 2025 and 100 MW in 2030.

3.5.2 Petroleum Sector:

A) Consumption & growth

Petroleum products constitute about 44% of the Primary Energy consumption of Sri Lanka. The country refines about 32% of its requirement in the solitary Sapugaskanda Refinery and the rest of the refined products are imported. The growth of petroleum products has been dissimilar across the product line, as can be seen in the Fig 3.5.12 below.:

Fig-3.5.12: Consumption of Petroleum Products -1990 – 2016



kt = kiloton, LPG = liquefied petroleum gas.
Source: Sri Lanka Sustainable Energy Authority. 2018. *Sri Lanka Energy Balance 2016.*

(Source ADB Sector Assessment , SLSEA, Govt of Sri Lanka)

As per the Energy Balance Report 2017, Sustainable Energy Authority, the consumption of Petroleum products in 2015 was 3.6 Million MT and increased to about 5.3 Million MT in 2017. The key consumption data between 2005 and 2017 is as in the table below:

Table-3.5.6: Consumption Petroleum Products in Sri Lanka

kt	2005	2010	2014	2015	2016	2017
LPG	165.0	187.5	231.6	293.4	356.0	412.0
Naphtha	124.9	54.1	93.9	97.2	174.3	139.3
Gasoline	463.0	616.5	835.9	1,009.0	1,463.1	1,488.9
Kerosene	209.0	165.1	121.8	130.2	172.4	159.0
Auto Diesel	1,665.3	1,696.8	1,960.2	1,996.0	2,148.8	2,340.0
Super Diesel	16.0	12.2	36.4	46.4	86.6	91.5
Furnace Oil	972.8	994.5	749.4	441.0	268.2	724.8
Total	**3,616.0**	**3,726.7**	**4,029.1**	**4,355.6**	**4,669.4**	**5,355.5**

(Source: Energy Balance 2017,SLSEA, Govt of Sri Lanka)

An analysis of the absolute growth in consumption of the respective petroleum products and their share in the total consumption as in 2005 and 2017 has been carried out. The details have been mapped in the table below:

Table-3.5.7: Growth and share of petroleum products between 2005 and 2017

Petroleum Products	Consumption		Share in Consumption		Growth between 2005 and 2017
	2005	2017	2005	2017	
LPG	165	412	5%	8%	150%
Naphtha	125	139	3%	3%	12%
Petrol	463	1,489	13%	28%	222%
Kerosene	209	159	6%	3%	-24%
Auto Diesel	1,665	2,340	46%	44%	41%
Super Diesel	16	92	0%	2%	472%
Furnace Oil	973	725	27%	14%	-25%
Total	3,616	5,356	100%	100%	48%

(Source Energy Balance 2017, SLSEA)

It can be seen from the table3.5.7 above that while the absolute growth in total consumption between 2005 and 2017 was about 48%, the growth of Petrol and LPG stands out. The absolute growth of Petrol was 222%, which is much higher than the absolute growth of 48% in the total petroleum consumption, i.e. 48%, in this period. For LPG, the growth was 150% in 2017 as compared to 2005. Their share in total consumption has increased; Petrol from 13% in 2005 to 28% in 2017, and LPG from 5% in 2005 to 8% in 2017. The growth of Diesel has been organic, and similar to the overall growth in consumption of the petroleum products. The share of Diesel has slightly reduced from 46% in 2005 to 44% in 2017, though it has grown by 44% during this period. Furnace oil and Kerosene have witnessed a negative growth during this period. Significant is that the share of Furnace Oil which was 27% in 2005 has reduced to just about 14% in total petroleum consumption.

B) Petroleum Pricing and Subsidy:

The pricing of petroleum products (Petrol, Diesel, Kerosene etc) are under Government – controlled regulators. The subsidy is maximum in Petrol followed by Auto Diesel. For 2017, as per Ceypeto, the subsidy amounts to almost 34 Billion Rupees, towards the standalone sales from Ceypetco. Details of subsidy per litre and the volumes have been compiled from information provided in the Annual Report

2018 of Ceypetco and have been presented in Table 3.5.8 below

Table-3.5.8: Subsidy towards key Refined Petroleum Products: (Source CEYPETCO Annual Report 2018)

Subsidy of Ceypetco in Petroleum Products in Sri Lanka - 2017					
Fuel	**Selling Price**	**Subsidy**	**Quantity in Mn KL**		**Subsidy of Ceypetco**
	Rs / litre	Rs / litre	CEYPETCO	Others	Billion Rs
Petrol 92 Oct	126.44	13.44	1.24	0.48	16.67
Petrol 95 Oct	137	13.31	0.17	0.09	2.26
Auto Diesel	97.46	5	1.87	0.33	9.35
Super Diesel	104.31	0		0.13	0.00
Diesel for Elec	95.41	0.41	0.397	0.1	0.16
Kerosene	70.48	27.63	0.199		5.50
Total					**33.94**

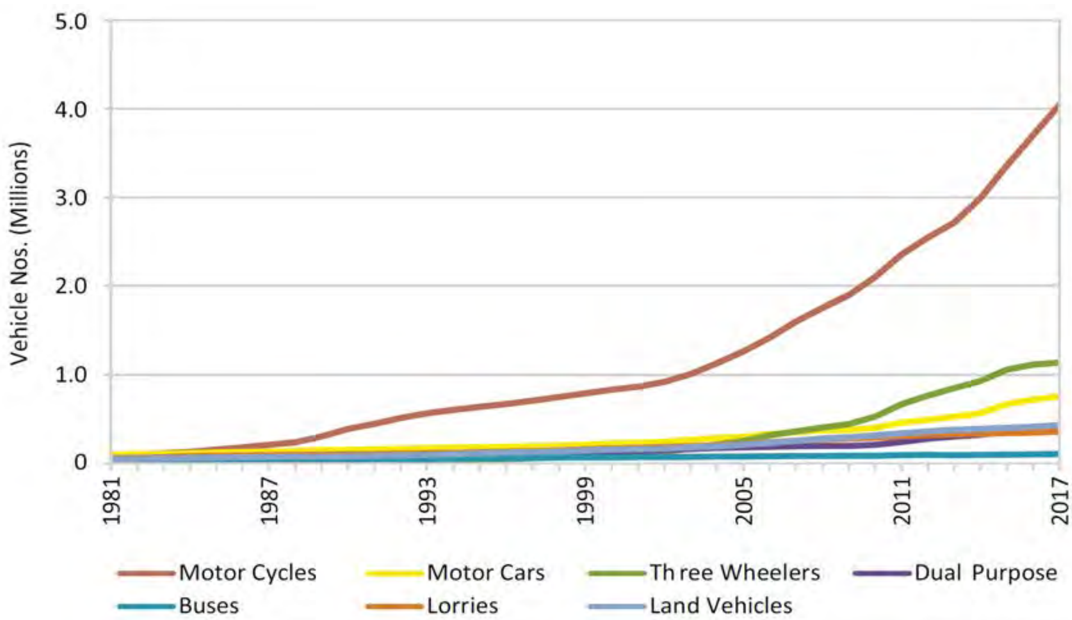
The impact of subsidized petroleum products over the years has been quite substantial. As per the Annual Report-2018 of Ceypetco, the accumulated losses of about SLRs 219 Billions.

C) Demand Outlook for Petroleum Products

i) Petrol / Gasoline: As discussed at 3.5.2 (A) above, the absolute growth of Petrol between 2005 and 2017 was 222%, which is much higher than the absolute growth of 48% in the total petroleum consumption in this period. From the sales figures in the Annual Report 2019 of CPC, the growth rate for gasoline works out to about 11% over the previous year. This appears to be unusual and is an impact of the reduction in petroleum prices considering the highs in 2012 & 2013. As discussed at 3.5.2(A) above, the share of Petrol has grown from 13% in 2005 to 28% in 2017.

The reason is that the rising per capita income has boosted the sales of 4-wheelers as well as 2-wheelers. Sri Lanka had 6.3 million vehicles by the end of 2015, 3.3 million (52%) are motor cycles, 1 million (16%) are three-wheelers and 672,000 (11%) are motor cars. From 2008 to 2015, the cars, three-wheelers and two wheelers, registered in the category of private vehicles, have doubled, as indicated in the figure 3.5.13 below:

Fig-3.5.13: Growth of Automobile Fleet in Sri Lanka



(Source: Sri Lanka Energy Balance 2017 / SLSEA)

In 2017, the penetration of cars was only 24 cars per 1000 people. With the gasoline based automomobile market poised to grow between 5 – 6 % CAGR, the sales of petrol are being assumed to grow at 6% CAGR till 2025 and subsequently at 5% with the government supported introduction of EVs.

ii) Diesel: As per the consumption of Diesel, 84% of its demand is from the transportation sector. The GDP is expected to grow at 4.7 – 5% CAGR. The growth rates of commervial vehicle markets comprising of 3-Wheelers, LCVs and HCVs are expected to match the GDP rates. The consumption of Diesel in the power sector has already declined, and as per CEB's LTGEP 2020-39, it shall be phased out from the power sector by 2021. The growth rate of consumption of Diesel in the past 4-5 years has been a little above 4%. This growth is likely to continue in the mid-term and long-term.

iii) LPG: As discussed at 3.5.2 (A) above, the absolute growth of LPG was 150% between 2005 and 2017, which is much higher than the absolute growth of 48% in the total petroleum consumption during this period. The growth of LPG was about 20% in 2017 and 16% in 2018. The growth is likely to continue. Considering that the country is dependent on 40% of its Primary Energy requirements on Bio-fuels, the penetration of LPG is assumed to grow at about 8% on a mid-term basis till 2025, and thereafter at 6%.

iv) Naphtha, Heavy Oils and Kerosene: Sri Lanka has already dec0mmissioned its Furnace Oil based power plants from 342 MW in 2011 to 160 MW by 2016. As per the LTGEP 2020-2034, FO-based capacity would remain just about 100 MWs with efficient Reciprocating Engines, while the Naphtha-based power plants would be phased out in 2020 and its consumption shall zero down by 2020. With the growth of LPG, the consumption of Kerosene shall remain stable at present consumption levels in medium to long-term.

D) Summary of Mid-term and Long-term demand

As analysed above, an attempt has been made by the author to forecast the demand for key petroleum products, Petrol, Diesel and LPG, in the Short, Mid & Long-term. The growth rates for Petrol has been taken as 6% till 2030 and thereafter 5% till 2040. For Diesel, it has been taken as 4.5%, the prevailing growth rate. The Government plans to minimize the firewood consumption and so, LPG is likely to make deep penetration. The growth rates for LPG have been taken as 8% till 2030 and 6% thereafter. The summary of emerging demand is as indicated in the table 3.5.9 below:

Table:3.5.9: Summary of Mid-term to Long-term demand of Petrol, Diesel and LPG

Growth of Petrol, Diesel LPG (Kt)								
Fuel	Growth Rate	2014	2017	2020	2025	2030	2035	2040
Petrol	6% till 2030, 5% post 2030	836	1488	1772	2372	3174	4051	5170
Diesel	4.5%	1996	2431	2774	3457	4308	5369	6691
LPG	8% till 2025, 6% therafter	232	412	519	763	1021	1366	1828

3.6 Gas demand estimation

3.6.1 Estimating landed cost of LNG and supply costs.

As concluded from the several policy initiatives of the Government, MPRD and other agencies like the SLSEA, PUCSL, PRDS and CEB, Bangladesh is already geaded for introducing gas in its energy basket. The National Energy Policy & Strategies 2019 has earmarked development of LNG and Gas Pieline infrastructure. The government approved Policy on Energy Mix (2019) has earmarked 30% of firm energy from LNG. The PRDS has also brought out a draft National Policy on Natural Gas in 2019.

In addition to pursuing the prospects of domestic production of natural gas from its sedimentary basins, in particular the M2 block, Sri Lanka has been discussing the establishment of the LNG receiving infrastructure on a Government-to-Government basis for import of gas.

An attempt has been made by the author to estimate the landed LNG prices and expected retail prices of Piped Natural Gas / Compressed Natural Gas in Sri Lanka. The costs would depend upon depend on the following elements:

a) Delivered Ex Ship (DES): For term LNG, a parity of 12.5% DES has been assumed based on the trend of contracting in Asian Countries / India.

b) Regasification of LNG and Other charges costs: These may cover all miscelleneous ecpenditure and Regasification costs. In India, Regasification costs are just under a 1 $/mmbtu. For new terminals, cost may be more depending upon the Capex and structuring of equity/debt and interest rates etc. Another 1 $/mmbtu has been assumed for other costs related to unloading etc. Total cost of Li 2$/mmbtu.

c) Trunk Pipeline transportation costs: 1 $/mmbtu, based on costs in India for trunk pipelines. N kept for lower through puts.

d) Distribution and marketing Costs: As per the experience in the neighbouring India, which has similar socio-economic demography, acquiring of 'Right of Way' and land can be expensive and can have large variation in the costs. Post the 9th and 10th round of bidding for India's CGD, the performance of the companies is yet to establish the Opex and Capex. But going by the Annual Reports of the leading Indian Gas companies, and the data of Operating Margins, Opex, EBITDA and PAT per unit volume, a margin of about 5$/mmbtu can be assumed for retail distribution costs.

As such, LNG to bulk consumers can be made available at around 8 – 9 $ /mmbtu, and for the retail consumers in CGD network at about 13 – 15 $/mmbtu as illustrated in Table 3.6.1 below:

Table-3.6.1: Estimation for Cost of Supplies of LNG to Bulk / Retail Consumers Author / Other Sources)

Estimation of LNG Prices			
A). Crude Prices (in $/bbl)	40	50	60
B) DES at Crude Parity 12.5% (in $/mmbtu)	5	6.25	7.5
C) Regasification and Other cost	2	2	2
D) Pipeline Transportation Costs (Bulk or Trunk)	1	1	1
E) Bulk Consumer Costs (B+C+D)	8	9.25	10.5
F) Retail Distribution Costs	5	5	5
G) Retail Consumers Costs (E+F)	13	14.25	15.5

1.Term contract prices are negotiable and downward prices can be explored
2. Liquefaction, Pipeline and Distribution costs can be higher if consumption is low

There is following scope for savings in costs by sourcing LNG:

- LNG price can be negotiatedto upto 11% of Crude parity or a mix of Crude and Gas indices.
- Sourcing cost can be economised using a mix of 'Term' and 'Spot' contracts.

For the retail customers, gas costs can increase if the consumptions or population density is low.

3.6.2 Estimating potential gains on switching to gas

(A) Potential gains on fuel substitution by consumers of Petroleum Sector

The successful penetration of LNG / Gas in consumer segements of Automobile, Industry, and Domestic consumers petroleum neighbouring country like India is an impetus to explore the possibility of utilization of LNG/ Gas in Sri Lanka. The specific costs of thermal energy at prevailing retail prices of petroleum products (Petrol, Diesel, Kerosene and also LPG) in Sri Lanka are in the range of 14 to 27 $/ mmbtu as in the Table 3.6.2 below:

Table-3.6.2: Comparison of Specific cost of thermal energy in LPG, Petrol and Diesel in Sri Lanka

Fuel	Price	Unit	GCV	Unit	Price In SL Rs/1000 Kcals	Price In USD/ mmbtu
LPG Cyl 12.5	1493	Rs/Cyl	11,900	Kcals/Kg	10.04	13.68
Petrol 92	137	Rs/Litre	8,269	K cals/litre	16.57	22.58
Petrol 95 Oct	161	Rs/Litre	8,269	K cals/litre	19.47	26.54
Auto Diesel	104	Rs/Litre	9,185	K cals/litre	11.32	15.43
Diesel (Euro 4)	132	Rs/Litre	9,185	Kcals/Litre	14.37	19.59
HFO	96	Rs/Litre	11,200	Kcals/Litre	8.57	11.68
Industrial Kerosene	110	Rs/Litre	8,880	Kcals/litre	12.39	16.88

Notes
1. Densities (Kg/litre): Petrol - 0.745, Diesel - 0.835, HFO - 0.95
3. Conversion from Kcals to btu: 1 K cal = 3.966 btu
2. Exchange rate is 1 USD = 185 SL Rupees
4. Prevailing prices as per CEYPETCO as on 1st April 2020

(Source: Author / Industry sources)

A comparision of the estimated deliverd prices of LNG, (as in Table 3.6.2 above) with the prevailing Specific cost of thermal energy in different petroleum products (as in Table 3.6.2 Above) reflects the price arbitrage for the retail and bulk consumers. This arbitrage is a key incentive for motivating consumers for fuel switch from petroleum products towards gas/LNG. The arbitrage or benefit with LNG (estimated at 50 $/mmbtu) is illustrated in the table 3.6.3 below:

Table-3.6.3: Comparison of cost benefit in LNG (Crude @ 50 $/bbl) for Petroleum products in Sri Lanka

Fuel	Price	Unit	Price In SL Rs/1000 Kcals	Price In USD/ mmbtu	Price of LNG for Retail		Price of LNG for Bulk	
					Crude @ 50 $/ bbl	Benefit	Crude @ 50 $/bbl	Benefit
LPG Cyl 12.5	1493	Rs/Cyl	10.04	13.68	14.25	-4%	9.25	44%
Petrol 92	137	Rs/ Litre	16.57	22.58	14.25	37%	9.25	80%
Petrol 95 Oct	161	Rs/ Litre	19.47	26.54	14.25	46%	9.25	89%
Auto Diesel	104	Rs/ Litre	11.32	15.43	14.25	8%	9.25	55%
Diesel (Euro 4)	132	Rs/ Litre	14.37	19.59	14.25	27%	9.25	72%
HFO	96	Rs/ Litre	8.57	11.68	14.25	-22%	9.25	28%
Industrial Kerosene	110	Rs/ Litre	12.39	16.88	14.25	16%	9.25	62%

Notes
1. Densities(in Kg/litre): Petrol - 0.745, Diesel 0.835, HFO - 0.95
3. Landed price of LNG as per the estimates of author
2. Exchange rate is 1 USD = 185 SL Rupees
4. Prevailing prices as per CEYPETCO as on 1st April 2020

(Source: Author / Industry data)

It can be seen from above that there is a significat benefit for switching from Diesel and HFO for bulk customers, in particular power plants. The annual consumption of all Liquid fuels (FO, Diesel & Naphtha) for power generation in 2017 was over a million tons. For the petrol consumers too, the benefit is about 37% – 46% of fuel cost, and there is a clear incentive to shift to cheaper LNG, even if it is more expensive than 20%. For Diesel consumers, there is not much incentive to switch to LNG.

The above prevailing prices of petroleum prices in Sri Lanka have an element of subsidy and therefore, do not reflect the costs to Ceypetco. The unsubsidized market prices would be higher, and would provide higher gains on switching to LNG / Gas. This is also true for LPG, which is also subsidized. In India, the subsidized LPG is almost similarly priced as in Sri-Lanka. However, Commercial and Unsubsidized LPG are in the range of 16 to 20 $/mmbtu. Once, the City Gas Distribution network is available, the fuel switch will commence, as CNG for petrol and diesel automobiles. The switch will be for 3-wheelers and 4-wheelers.

3.6.3 Gas Demand: Key Drivers

1. Macroeconomic factors

a) GDP Growth: The GDP growth has been a steady 5.5 – 6% per annum. The countrysy:s Central Bank of Sri Lanka has also forecasted a more conservative increase of 4.5 to 5 % from 2019 to 2023 in GDP in the short term as in the Table 3.6.4 below:

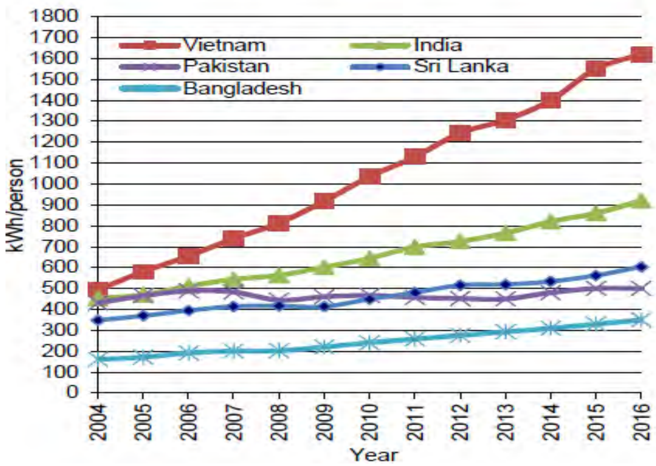
Table-3.6.4: Forecast of GDP Growth in Real terms

Year	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*
2017 Forecast	5.0	5.5	60	6.0	6.0	
2018 Forecast		4.0	4.5	5.0	5.0	5.0

(Source LTGEP 2020-2039 Draft)

b) Per capita energy consumption: Although the per capita power consumption in 2017has risen to 626 kwhr from 603 kwhr in 2016, and the trend reflects a steady growth, it is still behind the growth rates of neighbouring economies like India, or Vietnam. The growth in the neighbouring economies (Fig.3.6.1 below) is an indication of potential to improve its energy footprints.

Fig-3.6.1: Per Capita Power Consumption of South Asian nations in 2004-2017



(Source LTGEP 2020-2039 Draft)

c) Urbanization: About 8 districts including Colombo, have population of close to a million or more. Higher population concentration in Urban areas help in the penetration of energy resources like piped gas, electricity etc. As per the World Bank, the Urbanization in 2014 was about 18.3%, indicating potential for growth.

d) Geography: Sri Lanllka is an island with about 65,000 sq km of area, a shoreline of about 1340 kms, and about 4-5 ports as potential LNG import terminals.

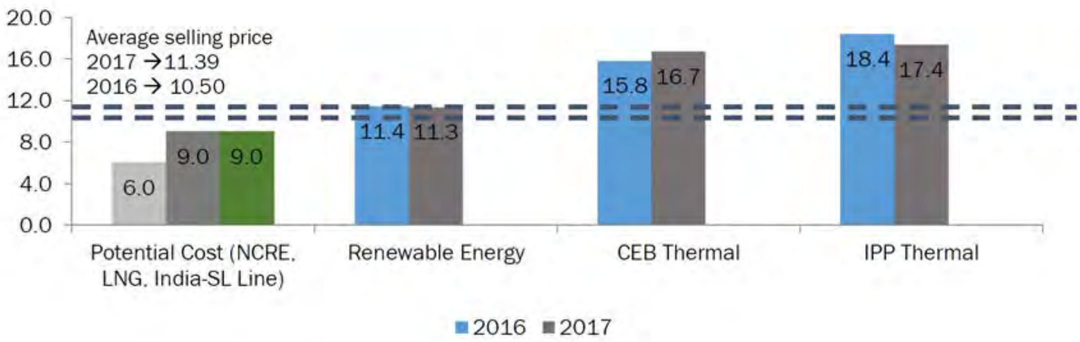
ii) Climate Change: Sri Lanka's Commitments in COP 21: Sri Lanka's economy is dependent on Tourism and Trade. It exports agricultural and marine sea foods. Tea, Coffee, Spices, Coconut are its key exports and Shrimps and sea-food are its marine export. The climate change can lead to severe adverse impact on its agriculture and also harm its mangroves, which are a key enable, r in rich marine life on its shoreline. The country is therefore committed to its INDC in the Paris Agreement (COP 21) and subsequent meetings (COP 22, COP 23). It has agreed for 20% reduction of GHG from Base by 2030 in the energy sector, which comes to reduction of 39,383 Gg by 2030. Out of this, 4% or 9.173 Gg are its Unconditional NDC, and remaining 16% are conditional. Its NDCs are endorsed by its institutions in the energy sector (SLSEA, PUCSL, NRESA, MPRD,CEB etc) and reflected in its planning like the formulation of its National Energy Policy and Strategies, National Gas Policy, Energy Balance, Long Term Generation Expansion Plan (LTGEP) etc Biomass / firewood form about 37% of its Primary Energy consumption. The country has lost its forest cover from 43% in 2048 to 23% in 2000, and after including the rubber, tea and coffee plantations, it stood at 29% in 2010.

As its NDC, Sri Lanka has committed to increase its land under forest cover to 32% by 2030. As such, the dependence on Bio-mass would have to be curtailed. The penetration of LPG or CNG would help in achieve.

iii) Supply side cost economies:

Power: The country has several power stations that operate on Oils (HFO, Diesel), which have higher cost of genertion than imported LNG. The Fig 3.6.2 compares the selling price of LNG with other sources of power:

Fig-3.6.2: Selling price of Electricity from LNG and other sources



(Source Sri Lanka InfraSAP@World Bank, IFC)

Consumers of refined petroleum products: LNG offers about 37-46% cost benefit over petrol as explained above.

3.6.4 Sector-wise analysis of demand

As brought out in various reports of CEB, SLSEA & PRDS; and also by the author above at 3.6.4, there is significant evidence for Sri Lanka to introduce gas as a key energy resource and achieve economic, environmental and social benefits in various sectors viz, power, industries, transportation, commercial and household. It can also be used for higher margins in its refinery operations and also as feedstock for propelling growth of fertilizers & petrochemicals.

However, to begin, the exiting sectors which can immediately reap benefits are the power sector, transportation and commercial sector using Petrol & Diesel, and, the domestic and commercial sector using the LPG. Sector-wise demand analysis is as follows:

i) Power Sector

The Draft LTGEP 2020-39 has recommended switching the liquid fuels to gas in its Base case. Further, in view of climate change concerns and the prevailing soft LNG prices, reduction in charter rates of FSRUs, and a number of new LNG Liquefaction projects in the pipeline, there may be a shift in the enrgy-mix for capacity addition. Coal-basd capacity may give way to gas-based capacity additions. So, two scenarios have been considered for evaluting demand for the Power sector, 'Scenario 1' being the Base case scenario in LTGEP 2020-39, for which the energy mix considered has the approval of the Sri Lanka government; and, the 'Scenario 2' which envisions lower prices of LNG and climate change concerns lead to shift in capacity addition from coal etc to gas. The demand is as follows:

a) Scenario-1: Base Scenario as per the LTGEP 2020-2039 Draft,

The demand for fuels as per Base Case in LTGEP 2020-2039 Draft is as in Table below:

Table-3.6.5a: Annual Fuel Requirement in Base Case Energy Demand

Fuel	Unit	2020	2025	2030	2035	2039
Oils	in 1000 MT	1588	88	89	93	69
Coal	Million MT	1.5	3.2	4.3	5.8	7.4
LNG	Million MT	0	0.8	1.1	1.3	1.5
Dendro	Million MT	0.6	0.9	1.2	1.5	1.8

Oils include Naphtha, HSFO, LSFO and Diesel. Beyond 2023, only 100 MW capacity on HSFO 180 is envisaged.

b) Scenario -2: Low prices of LNG & Climate Change concerns

However assumimg that the LNG prices are likely to stay soft in the mid-term and due to concerns for climate change, there could be say a 25% shift in capacity addition from coal to gas-based fuelled power plants. In such a scenario, the emerging demand could be as follows:

Table-3.6.5b: Annual Fuel Requirement in 25% Shift from Coal to Gas Based Capacity

Fuel	Unit	2020	2025	2030	2035	2039
Oils	in 1000 MT	1588	88	89	93	69
Coal	Million MT	1.5	2.8	3.6	4.7	5.9
LNG	Million MT	0	1.0	1.5	1.8	2.2
Dendro	Million MT	0.6	0.9	1.2	1.5	1.8

Oils include Naphtha, HSFO, LSFO and Diesel. Beyond 2023, only 100 MW capacity on HSFO 180 is envisaged.

ii) City Gas Distribution: Substituting Petroleum and Bio-mass in Transportation, Commercial and Household

The price arbitrage for the consumers of petrol and diesel and convenience of the piped gas supplies for domestic households may see a shift in demand from Petrol, Diesel and LPG to LNG. The LNG prices have witnessed strong corelation with the crude prices. Therfore, any increase in crude prices equally impact the LNG as well as the prices of the refined petrloleum products like Petrol or Diesel. As such, consumers who switch from petroleum products to gas remain insulated from any dissimilar impact on the LNG prices in future. The arbitrage in switching to gas will always be beneficial in the long run.

Further, the commitment of Sri Lanka in their Committed NDCs in COP21 would also call for measures to reduce Bio-mass. The obvious option would be to shift to CNG.

The penetration of gas and demand in the 'climate change' scenario, supported by low prices, has been estimated as follows:

- Petrol switch over to LNG: 10% in 2025, 20%-2030 and 25% thereafter till 2040
- Diesel switch over to LNG: 10% in 2025, 20%-2030 and 25% thereafter till 2040
- LPG switch over to LNG: 15% in 2025, 25% in 2030, 35% in 2035 and 40% thereafter

The equivalent demand for LNG emerges as in Table 3.6.6 below:

Table-3.6.6: Demand for LNG by Fuel Switch in Petroleum Sector

Fuel	Growth Rate	2014	2017	2020	2025	2030	2035	2040
Petrol	6% till 2030, 5% post 2030	836	1488	1772	2134	2539	3038	3877
Diesel	4.5%	1996	2431	2774	3111	3447	4027	5018
LPG	8% till 2025, 6% therafter	232	412	519	648	255	956	1097
LNG Demand					**0.6**	**2.1**	**2.5**	**3.4**

(Author's assumptions)

3.6.5 Demand Scenarios:

Based on the above scenarios of projecting demand for gas, three combinations of the demand have emerged:

Scenario 1: This maps the requirement of power sector as in the Base Case of LTGEP 2020-39 and negligible penetration in other sectors. This scenario does not factor in switching of fuel by petroleum sector. The demand for LNG in this scenario is about 0.8 MTPA in 2025 and rises to about 1.5 MTPA by 2040, as in the Table3.6.7a below:

Table-3.6.7a: Scenario 1: Base Case of LTGEP 2020-39 for Power and nil penetration in other sectors

Scenario 1: Base Case Requirement for Power and Nil penetration in Petroleum & Biomass					
	2020	**2025**	**2030**	**2035**	**2039**
Power	0.0	0.8	1.1	1.3	1.5
Petroleum & Bio-mass					
Total	**0.0**	**0.8**	**1.1**	**1.3**	**1.5**

(Author's assumptions)

Scenario 2: This maps the requirement of power sector as in the Base Case of LTGEP 2020-39 and penetration in other sectors as worked out for penetration in consumers of petroleum and household sectors due to climate change concerns as discussed at … above.. The demand for LNG works out to be about 1,4 MTPA in 2025 and increases to 4.9 MTPA in 2040, as enumerated in the Table 3.6.7b below:

Table-3.6.7b: Scenario 2: Base Case of LTGEP 2020-39 for Power and penetration in other sectors

Scenario 2: Base Case Requirement for Power and Petroleum & Biomass Fuel Shift					
	2020	**2025**	**2030**	**2035**	**2039**
Power	0.0	0.8	1.1	1.3	1.5
Petroleum & Bio-mass		0.6	2.1	2.5	3.4
Total	**0.0**	**1.4**	**3.2**	**3.8**	**4.9**

(Author's assumptions)

Scenario 3: This scenario assumes low LNG prices and Climate change concerns leading to about 25% shift in capacity from coal to gas in the power sector. The penetration in other sectors result in switching of fuel from petrloleum products to gas. Considering the prevailing global LNG environment, this appears to be a more likely scenario to emerge. The demand shall be about 1.7 MTPA in 2025 and go upto 5.6 MTPA in 2039, as brought out in Table 3.6.7c below:

Table-3.6.7c: Scenario 3: Shift in capacity addition from Coal to Gas and penetration in other sectors

Scenario 3:Shift in capacity addition from Coal to Gas and penetration in other sectors					
	2020	**2025**	**2030**	**2035**	**2039**
Power	0.0	1.0	1.5	1.8	2.2
Petroleum & Bio-mass		0.6	2.1	2.5	3.4
Total	**0.0**	**1.7**	**3.6**	**4.4**	**5.6**

(Author's assumptions)

3.6.6 Demand Summation & analysis

A) Demand Summation

The LNG demand in the above three scenarios have been summarised as in the table 3.6.8 below:

Table-3.6.8: Demand Summation of the Three Scenarios

Demand Summation					
	2020	2025	2030	2035	2039
Scenario 1	0.0	0.8	1.1	1.3	1.5
Scenario 2	0.0	1.4	3.2	3.8	4.9
Scenario 3	0.0	1.7	3.6	4.4	5.6

(Author's assumptions)

B) Analysis of Demand

In the present scenario of low crude and LNG prices, Gas-based capacity addition may be preferred. The demand in Scenario 2 or Scenario 3 are more likely to emerge. The following factors are supportive of the demand:

1. The draft LTGEP 2020-39 has been drafted after taking in the approved policy of Generation mix, which considers 30% from LNG based generation in 2040.
2. Coal-based plants are likely to face opposition from the local population.
3. Gas can also find its way in other sectors of the economy like Transportation, LPG, Industry and Commercial.
4. Other than power generation, Sri Lanka is also planning using the Hambantota port as an LNG Hub for trade. The Hambantota port is a deep water port and has potential for refuelling as it is strategically located between Singapore and Fujairah. It can be used for bunkering of LNG in ships and can also be utilised for regional trade in South Asia. By deploying smaller LNG Vessels, the FSRU at Hambantota can be used to redistribute or supplement the requirements of LNG Terminals in South India and Bangladesh. An agreement has been entered between the Board of Investment of Sri Lanka with Pearl Energy (Saudi Arabia) for a Floating storage LNG Trading facility. 1 Million MTPA FSRU, which can be moved in as early as in 6 months.

The FSRU mode is the best way to move forward. It has benefits over the terminals in term of low initial investments, quick start up and ramp up of supply, flexibility in quantities and de-hiring if not required.

3.6.7 Key Challenges for Gas Demand

1. **Renewables:** Sri Lanka has promoted Rooftop Solar in its 'Soorya Bala Sangramaya' Scheme. The LTGEP has considered the expected rooftop solar into account while working out the plan for sourcewise generation capacity expansion.

2. **Electric Vehicles:** The EVs offer environmental and economic benefits. The growth of EVs is likely to result in a decline in growth of consumption of petrol and diesel. On the other hand, it will increase the demand for power generation. Gas /LNG based power plants offer higher efficiencies and lower carbon footprints. With soft LNG prices and its lower environmental impact, the Gas/ LNG is likely to find favour.

3.7 Summary of Key Drivers for growth of Sri Lanka's Gas Sector

1. Government's resolve

The Sri Lanka government decision in Jan 2020 to go ahead with an LNG plant is a key indication of its resolve for accelerating the entry of LNG. Further, an agreement has been entered between the Board of Investment of Sri Lanka with Pearl Energy (Saudi Arabia) in August 2020 for a Floating storage LNG Trading facility at Hambantota port. With this, Sri Lanka aims to reap benefits of the first mover advantage for fostering regional trade in South Asia.

2. The Draft Long Term Generation Expansion Plan (LTGEP)

As compared to the capacity expansion plan in LTGEP 2018-2037, the LTGEP 2020-2039 Draft brings out a distinct shift in the capacity addition from 'coal dominant' to 'Coal-cum- LNG' based power plants forncapacity additions.

3. Climate Change commitments and reducing carbon footprints

The committed targets (NDCs) for increasing forest cover to 32% by 2030 in itself calls for decarbonization of its thermal power capacity. Gas-based plants offer about two-thirds carbon footprints as compared to coal-based plants.

4. Trend of LNG pricing

The current crisis of rockdown LNG prices do offer an opportunity for the consuming countries to bargain for better pricing for their Term RLNG contracts.

5. Cooperation with BBINS

Sri Lanka can colloborate with neighbouring India and Bangladesh for economic benefits in its LNG sourcing as well as for optimizing operational efficiency of its LNG terminals, viz, mutual cooperation for mitigating intermittent imbalances in supplies and consumption.

Chapter 4: Growth Potential for Nepal's Gas Sector

4.1 Key growth and economic data

Background

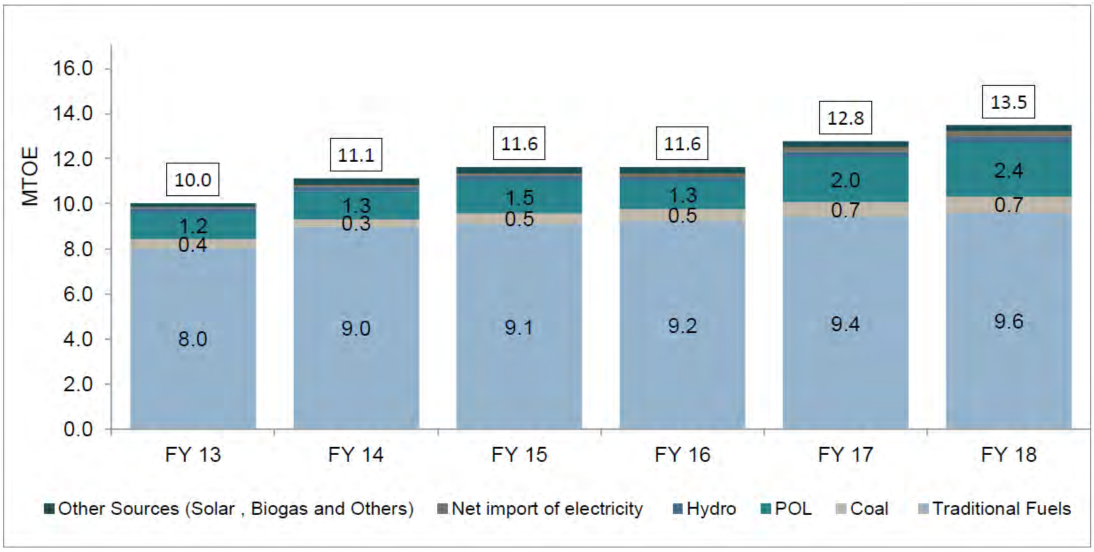
Nepal is a small land locked country of about 147,181 sq kms situated between China in the north and India on its East, South and West. Its southern-eastern tip is separated from Bangladesh by a only 27 km-stretch of Indian territory. In the east, the Indian state of Sikkim separates it from Kingdom of Bhutan. It has a population of just about 30 millions. The GDP of the country has grown steadily at around 7.5% pa since the early eighties. The country practiced monarchy and has slowly migrated to democracy. Economic ties with India were strengthened with the development of hydropower projects to power the economy.

Nepal's estimated per capita GDP in 2019 was only 1,048 $. The growth came down in 2018 to 4.5%. About 59% of its GDP is contributed by Services, 27% by Agriculture and remaining 14% from Industry. The unemployment rate is about 3%. About 25% population is below poverty line. As per UNDP (2018), HDI was 0.579 in 2018, well behind the average 0.642 for South Asia.

Energy Consumption:

Nepal's Primary Energy Consumption grew at a CAGR of about 7.7% between 2013 and 2015. In April 2015, a major earthquake struck and devastated many parts of Nepal including the Kathmandu valley, resulting in slowdown for a year. The growth since 2015 has been at a CAGR of about 5.5%. Nepal has been heavily dependent on traditional bio mass fuels (firewood, animal dung and agricultural residues) . In 2012-13, Bio mass fiuels had a share of 80% in its Primary Energy consumption. However, share of Biomass has been declining year-on-year. As per SAARC Energy Outlook 2030 / CRISIL Research the overall Primary Energy Consumption in FY 2018 was 13.5 MTOE, with nearly 72% share of traditional fuels.

Table-4.1.1: Growth of Nepal's Primary Energy sources from FY-13 to FY-18



(Source: CRISIL/SAARC Energy Outlook 2030)

In FY 2019, Bio-mass sources (Firewood, Agriculture Residue & Animal dung) comprised of 71 % of its Primary Energy consumption. Petroleum products and Power (own generation and imports), each constitute a share of 17 % and coal has a share of 5% in its Primary Energy basket.

Table-4.1.2: Share of energy sources in Nepal's Primary Energy

Source	Share (in %)
Bio Mass	71
Petroleum	17
Coal	5
Power (Major Hydro + Imports)	17

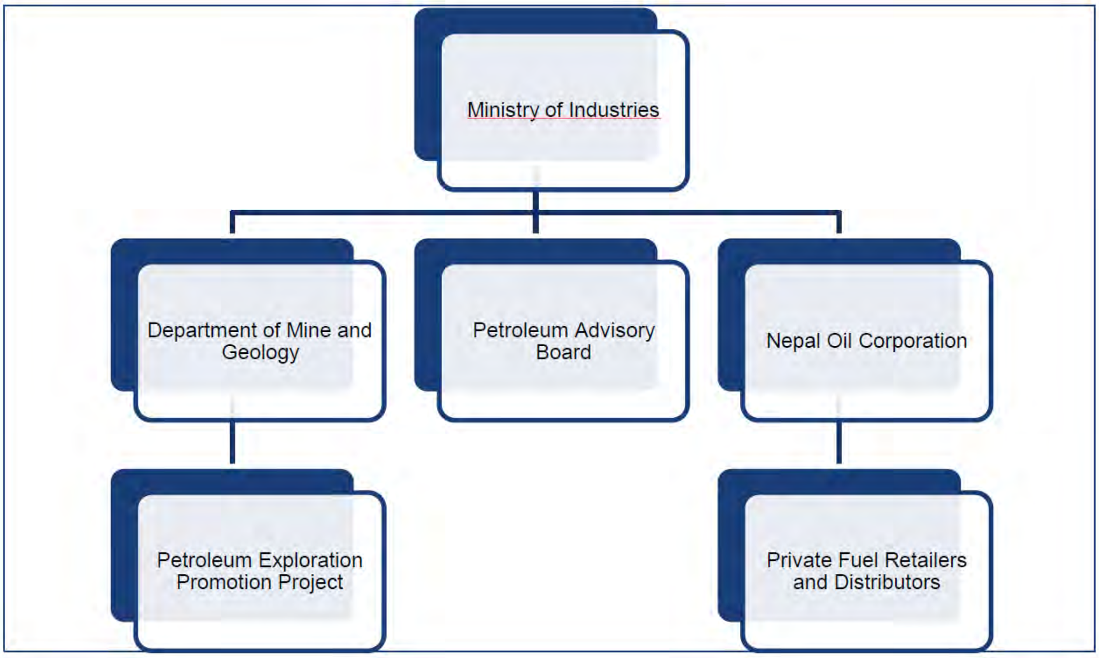
(Source: IRADEe Research)

In 2018-19, the per capita electricity consumption was only 245 kwhr, the lowest in the region. As per the World Bank Report, 93.92% population had access to Electricity in 2019.

4.2 Organogram of the Petroleum sector.

The country does not have any Oil or Gas deposits / reserves. The Petroleum products are imported from India and distributed across the country under control of the government. All operations are overseen and controlled by the Department of Trade under Ministry of Economic Affairs. An organogram of the sector is as follows:

Fig -4.2.1: Organogram of the Petroleum Sector



(Source: CRISIL SAARC Energy Outlook 2030)

The Department of Mines & Geology (DMG) overlooks all policies for the exploration, assessment and extraction of Nepal's Mineral wealth. The Petroleum Advisory Board comprises of senior officials of the various Ministries and exercises wide powers and responsibilities in matters associated with the petroleum related activities.

4.3 Regulatory Environment and Government Policies

4.3.1 Upstream: Policies & initiatives for growth of E & P

At present, Nepal do not have any oil & gas production. The Department of Mines & Geology (DMG) overlooks all policies for the exploration, assessment and extraction of Nepal's Mineral wealth. In 1982, Petroleum Exploration Promotion Project (PEPP) was carved out to accelerate the exploration of oil& gas resources. PEPP operates under the control of DMG.

Brief History of Exploration in Oil and Gas

Natural occurrences of gas & oil seepages have been present in the Dailekh region (Western Nepal) and Muktinath region (Higher Himalayas) in Nepal. The seepages evidently indicate presence of hydrocarbons (oil & natural gas) in the geology of the country. The Dailekh region has five visible seeps, with mild flare, two in Sirsasthan, two in Nabi Sthan and one in Lalat. These seeps have been worshipped as 'Jwala Devi'(or the deity of flame).

As per the exploratory surveys and field works, the shale beds in Siwaliks (the lower Himalayas) and the Terai region (the high plain lands stretching into the Indo-gangetic plains to the south) indicated 2-20 % of Total Organic Carbons (TOC). The shows of hydrocarbons in the Potwar Basin of Pakistan and the Assam basin of India in similar geological environment are good indicators of presence of oil & gas in sizable quantities in Nepal. The country has pursued exploration activities for over 50 years, summarised as below:

A) Initial Surveys leading to formation of exploratory blocks: A geological, aeromagnetic, gravity and seismic survey, covering an area of 48,000 sq kms, was conducted by DMG in 1978-79 with the help of IDA/ World Bank. Subsequently, the following surveys were also taken up:

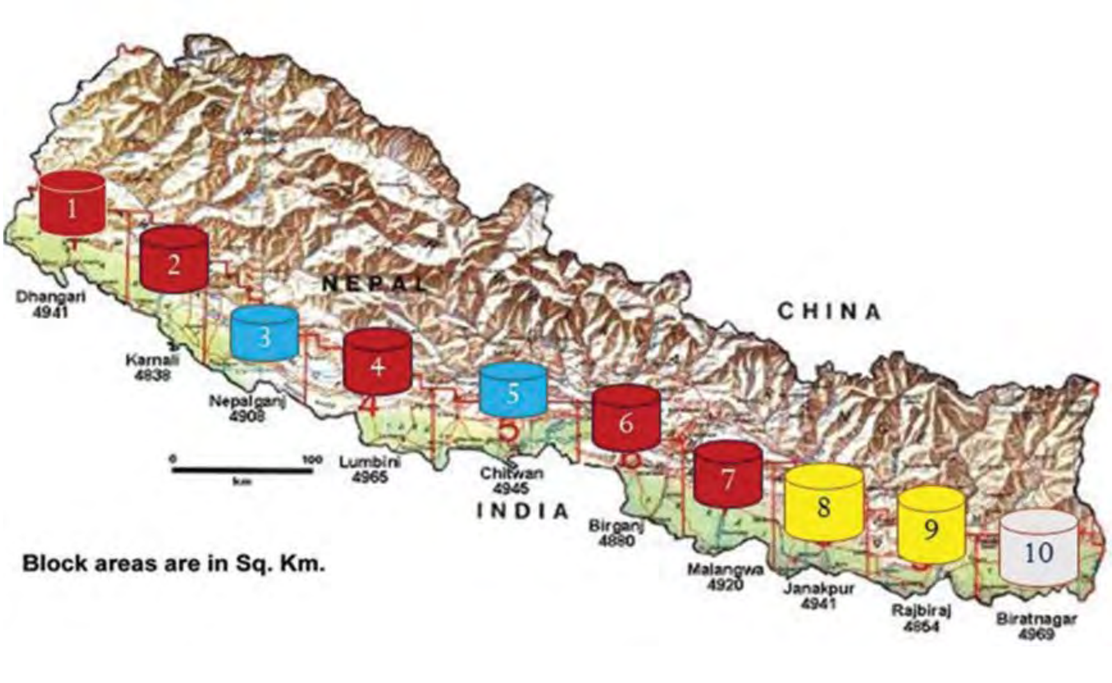
- Over 3,000 sq kms were surveyed by Petro-Canada and Compagnie General De Geophysique (CGG)
- Photogeological study over 60,000km2 area covering Terai and the Siwalik was carried out by Hunting Geology and Geophysics Ltd

These studies helped to identify the prospective regions in the Sivaliks and Terai regions in the southern part of the country. A total of 10 exploration blocks, each of approximately 5,000 sq kms, were demarcated for detailed exploration. These 10 blocks were:

Block 1 - Dhangari, Block 2 – Karnali , Block 3 - Nepalgunj, Block 4 - Lumbini, Block 5 - Chitwan, Block 6 - Birgunj, Block 7 - Malangwa, Block 8 - Janakpur, Block 9 - Rajbiraj and Block 10 – Biratnagar

The blocks have been illustrated in the map below:

Fig-4.3.1: Map of Nepal with the 10 Blocks for E&P of Oil and Gas



B) 1985 –onwards:

In1985, for the first time, PEPP invited bids from international oil companies (IOC) for these acreages. Shell Nepal B.V, (Netherlands) and Triton Energy Corp, (USA) jointly acquired the Block-10, Biratnagar to explore petroleum. It conducted detailed exploration by gravity and seismic survey (covering 2000 line km.) and also did petroleum exploration drilling up to a depth of 3,520 metres. But the hole appeared dry and then the block was relinquished in 1990

In 1998, Texana Resources Co. (USA) acquired the rights for exploration for Block-3 (Nepalgunj) and Block 5 (Chitwan). It carried out some field studies laboratory testing. But its exploratory efforts were not satisfactory as per the agreement

In 2004, CAIRN Energy PLC also leased five blocks as Block 1 (Dhangari), Block 2 (Karnali), Block 4 (Lumbini), Block 6 (Birgunj) and Block 7 (Malangwa). It did carry out some field investigations and laboratory tests of few possible source and reservoir rocks samples. However, they were not enthused to conduct extensive exploratory works. The Govt of Nepal cancelled their lease contract and both Texana Resources and Cairn Energy left Nepal in 2014 without any findings.

In 2012-13, Emirates Associated Business Group of UAE, were leased the exploration rights for the Block 8 (Janakpur) and Block 9 (Rajbiraj). However, they did not find any encouraging prospects and relinquished the blocks in less than two years.

In 2016, The Govt of Nepal / DMG / PEPP have commenced exploration for petroleum and natural gas in the Dailekh region with technical cooperation with the Govt of China under the 'China Aid on Oil & Gas Resources Survey Project'. Seismic surveys of 200LKm in 400 sq kms area along with magnetic surveys and some sample collections have been completed. Laboratory testing and the interpretation of the seismic data is being done in China.

It is also reported that the DMG has already proved 310 million cubic metres of methane reserves in the Kathmandu Valley, which can be used to substitute the LPG / Cooking gas.

4.3.2 Mid Stream and Downstream

Nepal does not have any petroleum refinery. The country imports its entire requirement of petroleum products and LPG from India. The import, storage and distribution is under control of the Government. In 1970, Nepal Oil Corporation (NOC), was established by the Government under the Companies Act 2021 91964). The Nepal Government owns 99.46% of the shares and the rest are held by government controlled Banks and Insurance companies. Only NOC is authorised to import, store and distribute petroleum products.

4.4 Analysis of the key energy sectors:

4.4.1 Power Sector:

As a Himalayan Kingdom with river valleys, Nepal has natural potential of hydropower. Its theoretical hydropower potential stands as 83 GWs and the techno-financially viable capacity potential is about 42,133 MWs. The potential river systems are Karnali & Mahakali (25,125 MW), Sapta Koshi (10,860 MW), Sapata Kandaki (5,270 MW) and Souther River (878 MW)

The per capita power consumption of the country in 2018-19 was about 260 kwhr. Power consumption has been increasing in double digits. As per Nepal Electricity Authority, the power sales in 2018-19 grew by nearly 13.69% over the previous year.

(A) Existing capacity & sources:

Hydro: As per their AR 2018-19, the grid connected Hydropower capacity of NEA is about 563 MWs while Isolated Small Hydropower capacity is about 4.54 MWs. In addition to this capacity, IPPs have an existing capacity of 560.775 MWs.

Thermal: The total capacity of Multi-Fuel / Oil engine based Generating units is about 53.4 MWs

Solar: Nepal has installed two plants of 50 KW each.

The total Grid-Connected Capacity is 1,178 MW while the Total Installed Capacity is 1,182 MWs

(B) Electricity Generation: Generation from NEA and IPPs installed capacity IN 2018-19 was about 4,632 GWHrs. This was well short of the demand, which was met by 2,813 GHHrs of imports from India via several transmission lines. In FY 2018-19, the domestic generation and imports grew by about 7%

over FY 2017-18. (Please see the table below)

Table-4.4.1: Generation in FY 2018-19: Source-wise and growth

Generation & growth in FY 2018-19					
	Unit	NEA	IPPs	Import	Total
Annual Generation	Million Units	2548	2190	2813	7551
Share in total Gen	in %	33.7	29.0	37.3	
Increase over 2017-18	in %	10.5	1	9	7

(Source: NEA Annual Reporte)

(C) Cross Border Electricity Trade (CBET) / Power Imports from India

Nepal has multiple transmission links with India. The population and industry concentration is more on the eastern and south-eastern part, also called the Eastern Terai. There are 4 links on 33KV lines and 3 links on 132 KV on the Eastern Terai Area. In the South-western Terai region with low population density, it has one link of 132 KV. A 400 KV line has been recently commissioned and power flows have commenced at 220KV. Nepal buys its major chunk from NTPC Vidyut Vyapar Nigam (NVVN), a Subsidiary of GoI-owned NTPC. Power Trading Corporation (PTC) , a GoI-owned power trading house, also has a minor share in exports to Nepal.

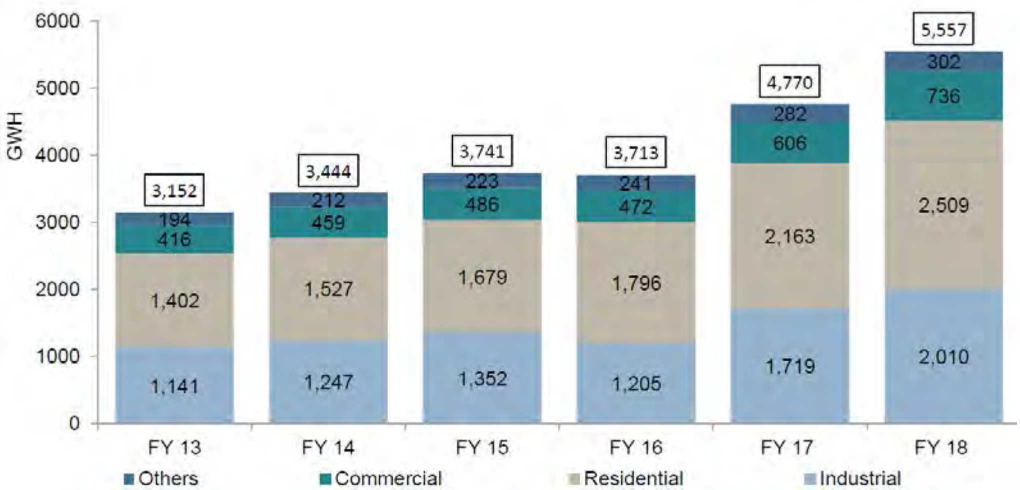
Nepal has also entered in an agreement with NVVN to access the two platforms of Power Exchanges of India, IEX and PXIL. The Indian electricity regulator, CERC has approved the same vide the CBTE Regulation- 2019, wherein, it has allowed neighbouring countries to gain access to Indian Exchanges through any Participating Entity approved by the Government of India and under the ambit of Trade Agreement between the two Governments. The entities would need to comply with the System and Operational compliances as per the Grid Code and Operation Procedures for scheduling, drawl, metering, settlement etc.

The CBTE Regulations have also helped Nepal to secure PPAs with India's Distribution Companies / Licensees for its upcoming Hydropower Projects. A Tri-partite agreement for sale of power between Nepal, India and Bangladesh has been signed recently. It was also reported that the promoters of Upper Karnali 900 MW Hydropower Project were also exploring to enter in PPA with Indian Distribution Entities / Licensees for achieving the Financial Closure of the project.

(D) Power consumption and access to electricity

In the past few years, backed by electrification of villages and Industrial growth, the electricity consumption has grown. The growth in power consumption from FY 13 to FY 18 is as follows:

Fig-4.4.2: Sector–wise consumption of electricity



(Source:NEA, CRISIL SAARC Energy Outlook 2030)

By the end of FY 19, about 78% population were provided access to grid-based power and another 9% to electricity from isolated and off-grid generating sources. In FY 19, several measures like Inspection of Metering systems of Industrial consumers, measures for prevention of theft, etc were vigorously pursued resulting in the growth of metered sales to 6,306 MUs, a growth of 15% over previous year.

(I) Growth projection of capacity additions:

i) Hydropower:

Firm capacity under construction: A large number of Hydro projects of different capacities are under construction/stages of development. About 120 projects totalling installed capacity of about 2614 MWs have already achieved financial closure and are under construction. A list of the plants (> 50 MW) with expected completion dates are enclosed at Ann. …

Planned Hydropower capacity additions: Further, another 137 projects of different capacities totalling 2,869 MWs are under various stages of development. NEA has already signed PPAs for about 6044 MWs capacity addition in HydroPower. In FY 2018-19 alone, it signed PPAs for a capacity of about 1,480 MWs.

ii) Other Renewable Energy Sources

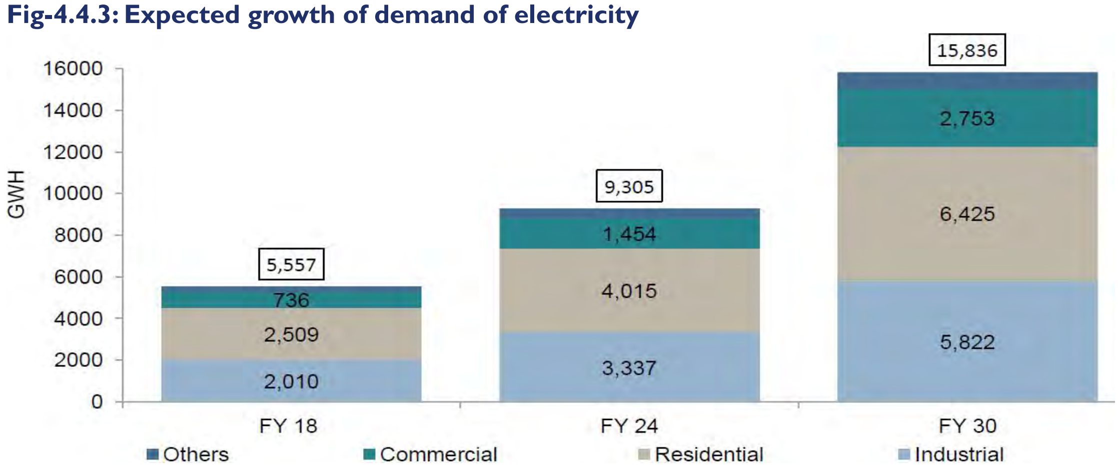
a) Solar Power: Average solar radiation is about 3.6 to 6.2 kwh/sqm per day and Insolation Intensity is 4.7 kwh/sqm. A quarter of country's area (37,501 sqkm) has Concentrated Solar Power (CSP) potential .As per the AEPC (Alternate Energy Promotion Centre), Nepal has a potential of 2100 MW of Solar PV.

b) Wind Power: Nepal has been pursuing Wind Power since 1967. Twenty five stations with Met Mast Towers have been installed to collect the data. The areas in five geographic regions have been identified which have power density of above 300 w/sqm and potential for installing wind-farms. Nepal plans to install a capacity of 20 MW of Wind Farms in Kathmandu Valley, which has power density of 400 – 1000 w/sqm.

iii) Growth projection of electricity demand:

The growth of demand for power shall be spurred by the increase in energy consumption by Industries, Commercial establishments and Residential consumers. The growth of demand for power is projected at CAGR of 9.1% in the Reference Case utilising a bottom up modelling tools (MAED-2) in the Long-Term Plan prepared by WECS. The demand is expected to reach 9,305 MUs by FY-24 and 15,836 MUs by 2030.

Fig-4.4.3: Expected growth of demand of electricity

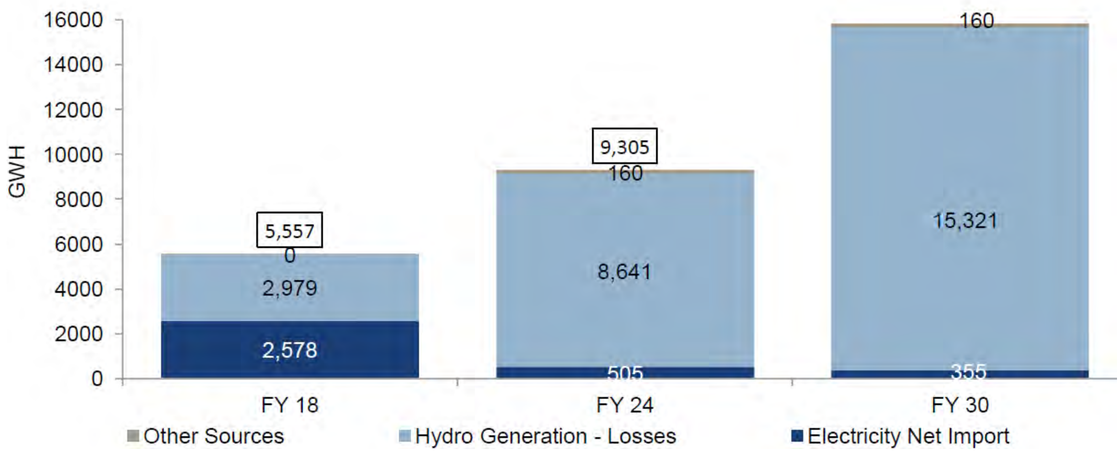


(Source: SAARC Energy Outlook 2030, CRISIL NEA,)

iv) Source-mix in growth

The share of imported power shall wither away as Nepal's Hydropower projects are commissioned and available for commercial operations. The imports shall be restricted to meet the peak demand during the 'Dry' months (December to April). The imports are expected to come down to 505 MUs in FY 2024 and 355 MUs in FY 2030.

Fig-4.4.4: Source-wise projection of electricity consumption

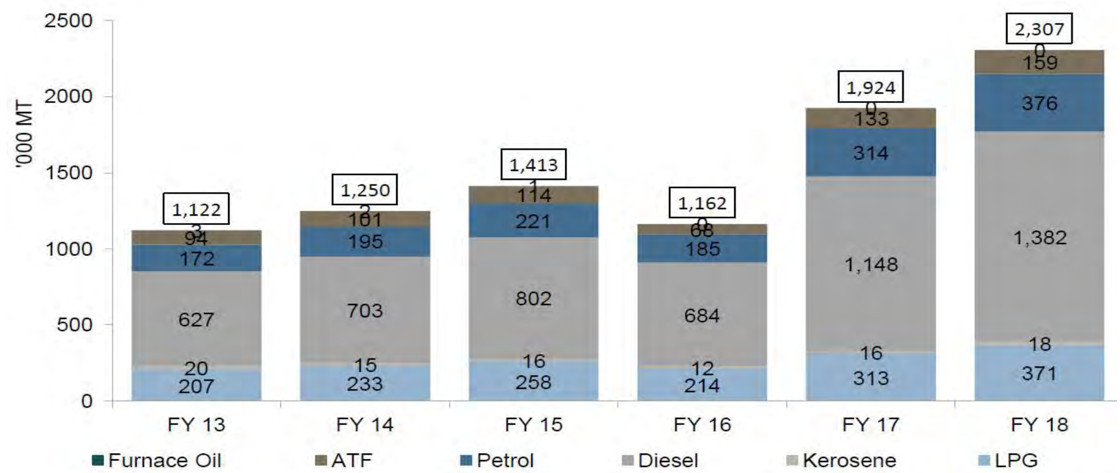


(Source: SAARC Energy Outlook 2030, CRISIL NEA)

4.4.2 Petroleum Sector

A) Consumption: Demand for Petrol, Diesel and LPG constitute over 92% of total consumption of all petroleum products. The demand for petroleum products has grown steadily over the past six years. In 2015, many regions of Nepal were devastated by earthquakes and the consumption came down in 2016. Leaving 2016 aside, Nepal's electricity consumption has grown by over 15% in the past six years. This is reflected by the imports of POL (Refer fig below)

Fig-4.4.5: Growth of Petroleum products from FY 13 to FY 18



(Source: CRISIL SAARC Energy Outlook 2030)

The trend has continued in 2018-19. Petrol consumption increased to about 419 KT (562,866 KL) and Diesel was 1,485 KT (1,702,157 KL).

B) Supplies: The petroleum products are imported from the NOCs of India, mainly Indian Oil Corporation Ltd. In 2017, IOCL and NOC agreed for a a 69-km pipeline from Motihari, India to Amlekhgunj, Nepal to minimize the road transportation constraints. In Sep 2019, this line has been commissioned. The pipeline has a capacity of 2 MTPA. In addition of ease in logistics, this pipeline will help Nepal to save upto 2 Billion NRs per annum. A feasibility study for an LPG pipeline connectivity with

India is also in an advance stage. In a joint working group meeting in Aug 2020, both sides have agreed to explore two more pipelines from the East and North.

C) Pricing & subsidies: Nepal imports its petroleum products from India's NOCs, mainly Indian Oil Corporation Ltd.. The duties and the taxes structure is lower than India and the prices are about 20% cheaper than India. The prevailing prices in Nepali Rupees (NRs) as on 1.4.2020 are as follows:

Table-4.4.2: Pricing of Petroleum Products as on 01.04.2020

Petroleum Oil Products	Unit	Price in NRs
LPG		
LPG Cylinder	14.2 kg	1375
Petrol 95 Oct	Litre	96
HSD	Litre	85

(Source: NPC / IRADe)

Petrol and Diesel are sold by NPC at market prices. LPG's prices are subsidized. The losses in LPG are made up from Petrol and Diesel.

D) Demand projections for Petrol, Diesel and LPG

The GDP is expected to grow at 4.5 to 5 % from 2019 to 2030. While the Primary Energy is expected to grow at around 3.8%, the growth of petroleum products and LPG will be dissimilar and much higher. Thegrowth in petrol is backed by about 7.8% growth in passenger vehicles (2, 3 & 4-wheelers), in the coming years. Petrol is likely to grow at a CAGR of 8%. Diesel is consumed by transport (80%) and industries (11%). The growth in demand for diesel is backed by growth in these sectors and is likely to grow at 8.2% through 2030. The entire requirement of the fossil fuels is to be imported as brought out in the table below:

Table -4.4.3: Expected imports of hydrocarbon fuels. (Petroleum products, LPG and Coal)

FUEL	FY 24	FY30
Key petroleum oil products (Petrol, Diesel, Kerosene, LPG, Furnace Oils, ATF) in kilo tonne	3,825	5,982
Coal (in thousand tons)	1,892	2,985

Coal Sector

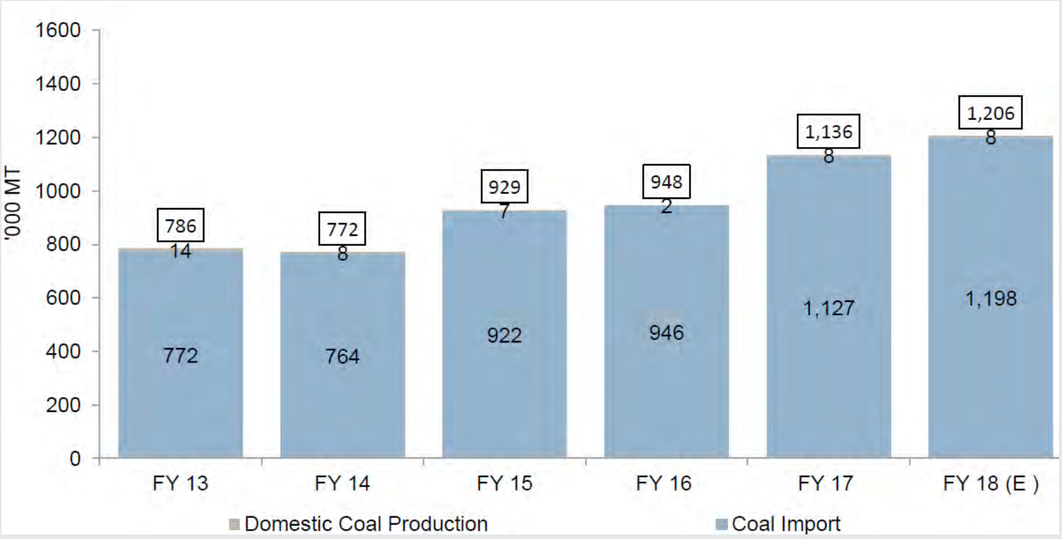
Coal has a share of about 5% in the Primary energy basket of Nepal. Except for domestic heating & cooking, almost the entire coal is consumed by the Industries and Commercial sector. Industries use coal for thermal applications in furnaces, boilers or process heating. It constitutes about 54% of the fuels consumed by the Industries. Coal consumption has been growing at a CAGR of about 9%.

A) Production, Consumption & Supplies: Nepal has scarce coal reserves. These are mainly:

- Quaternary Lignite in Kathmandu Valley
- Dang
- Siwalik
- Gondwana

Only Dang and Quaternary lignite are of commercial significance. However, coal production is just about 1% of its requirement. It imports its coal from India. In FY 2018, its total coal consumption was 1,206 K MT, out of which it imported about 1,198 K MT from India (Refer Fig below)

Fig-4.4.6: Coal Imports and Production from FY-13 to FY-18

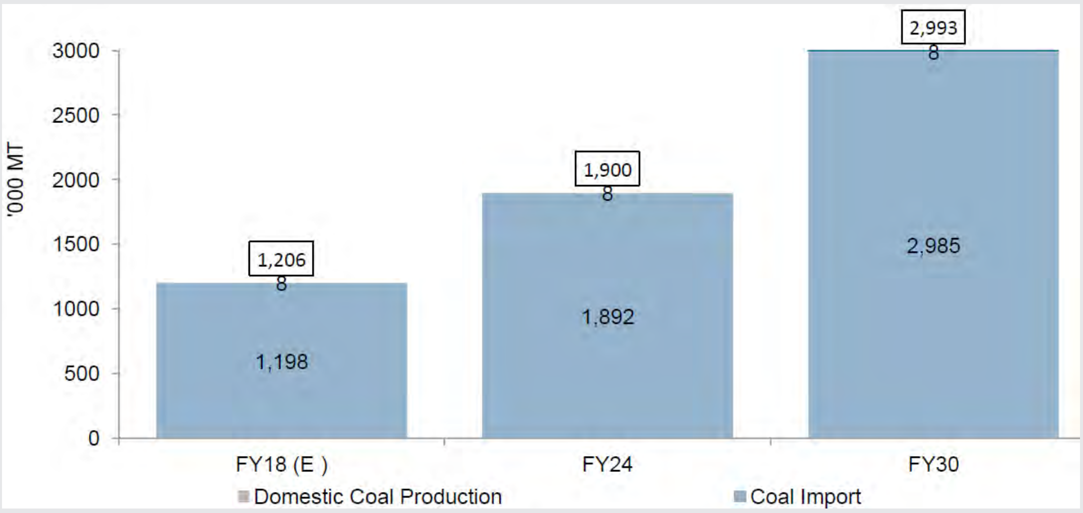


(Source: CRISIL SAARC Energy Outlook 2030)

B) Demand Projections

As per SAARC Energy Outlook -2030 report, Nepal's primary energy consumption is expected to grow at about 8.4%. Further, the share of industries in Nepal's GDP has been increasing, and, coal which constitutes over 50% of Industrial energy demand is expected to grow at a CAGR 8% till 2030. Its consumption is likely to reach about 2,993 K MTPA (or 1,706 KTOE). Domestic production is miniscule at just about 8,000 MT per annum, and is likely to remain stable. The coal requirement is projected to be met from imported coal, as in the figure below:

Fig-4.4.7: Projection for Coal Imports and Production



(Source: CRISIL SAARC Energy Outlook 2030)

Coal is imported from India and is available at around 15-20 NRs/Kg, depending on the quality, quantity, shortages and the terms & conditions.

4.5 Gas Supply options and feasibilities

At present, Nepal does not have any natural gas supplies or any infrastructure to receive gas supplies. The demand for gas emerges only if its economic advantage over other sources is established on a long-term basis and consumers are comfortable to switch over their prevailing fuel options in its favour. Once the economic advantage of gas is established, its demand can be worked out by estimating the extent of substitution or penetration in the basket of fuel that it can replace.

This study has attempted to explore the options of gas supplies and estimate the costs. It also compares the specific cost of thermal energy of various fuels to establish the extent of the economic advantage of gas over other fuels, if any. It also explores the potential regions and populations where it is economical for gas to penetrate and replace more expensive fuels.

4.5.1 Exploring gas supply options and estimating landed cost of gas.

Nepal does not have any prospective gas fields or reserves. Gas supplies have to be imported from neighbouring countries. India and China are the two neighbours and the demand of both countries is well short of their production. Bangladesh, which is separated by a small patch of 30 kms from Nepal's South-eastern borders, too is short of gas. These countries are importing LNG to sustain their demand. Bhutan, separated by the Indian state of Sikkim too does not have any gas resources.

Gas supply option from China is impractical as it involves a long distance and a harsh mountainous terrain as compared to India. Further, Nepal's population density is in its South, South-eastern, and Central regions, which have close proximity to India, and India is a natural choice for any gas supplies.

Three supply options have been considered, i.e.,

- **Option A:** A dedicated trunk pipeline connecting with nearby take-off point of India's Trunk Pipeline which has spare capacity on Contract Carrier basis. LNG shall be tied up with about 75-80% as Term LNG and the rest as Spot LNG.
- **Option B:** A number of dedicated small diameter pipelines from the CGD network of the Geographic Areas (GA) in the adjoining districts with India. The spare capacity of India's pipeline would be tied up as per the regulations. LNG would be tied up in bulk and distributed as per the demand at various end-use locations.
- **Option C:** 'Small-scale /Virtual LNG' Supply Chain using Trucks/Lorries with Cryogenic Containment system and Vaporiser stations at consumption points. This obviates the need for a Pipeline for supply of gas. The mode is gaining popularity as experienced by the CGD networks where pipeline connectivity is delayed or stuck or not planned. LNG supplies by cryogenic road tankers to CGD network in Bhuvneshwar in neighbouring India is an example of 'Small-scale / Virtual LNG'.

The supply chain analysis and expected landed cost under these options is as follows:

A) Option A: A dedicated pipeline from India for RLNG and landed cost

In this option, LNG would be sourced from Dhamra (and later from the proposed Kukrahati Terminal near Haldia) and transported by GAIL's Dhamra-Angul-Bokaro-Jagdishpur Expansion and take off from Barauni or Gorakhpur. A firm tie up of about 70-80% of the capacity would be required to ensure pipeline utilization and stability in pricing.

The following assumptions /costs for the supply chain have been made for estimating the landed cost under this option:

An upfront tie up of Term-LNG from the nearest LNG Terminal, i.e. Dhamra.

1. The DES prices have been assumed at Crude Parity of 12.5% in $/mmbtu. The cost have been worked out at Crude Prices at 40, 50 & 60 $/bbl.
2. Regasification and other costs at the terminal including Port Charges, Taxes & Duties, have been taken as 2 $/mmbtu
3. The Pipeline tariffs for the Indian pipelines from Dhamra are yet to be finalized. They have been assumed as 1.5 $/mmbtu.

4. A pipeline connecting Kathmandu with GAIL's Jagdishpur Expansion from Gorakhpur (Southern Route) or Barauni (South-Eastern Route), each of 250-300 kms length.
5. The Pipeline of 12-inch at pressure of 95 Kg/cm2 can easily meet the requirement equivalent to 1500 – 2000 ktoe.
6. The cost of pipeline laying is derived from the contracts awarded by GAIL in 2016-17(@ INR 50-60 Millions/km for a 24-30 inch high pressure line) by discounting for Diameter and escalating at 5% per annum and for the difficult terrain.
7. Levelized pipeline tariffs with margin assumed as 1.5 $/mmbtu.
8. The distribution costs would include connecting spurs to nearby population along the route

The estimated landed cost of gas for crude prices at 40, 50 and 60$/barrel works out between 15 – 17.5 $/mmbtu as follows ;

Table-4.5.1: Estimation of Landed cost of LNG in Option A for Bulk and Retail Consumers in Nepal

Estimation of Landed cost of LNG by Pipeline in Option A

A). Crude Prices (in $/bbl)	40	50	60
B) DES at Crude Parity 12.5% (in $/mmbtu)	5	6.25	7.5
C) Regasification and Other	2	2	2
D) Pipeline Tpt Costs:within India	1.5	1.5	1.5
Pipeline Tpt Costs: India – Nepal	1.5	1.5	1.5
E) Bulk Consumer Costs (B+C+D)	10	11.25	12.5
F) Retail Distribution Costs	5	5	5
G) Retail Consumers Costs (E+F)	15	16.25	17.5

Notes
1.Term contract prices are negotiable and downward prices can be explored
2. Liquefaction, Pipeline and Distribution costs can be higher if consumption is low

(Author's assumptions)

B) Option B: Multiple Links with the Gas pipelines feeding Indian GCD Network in bordering districts and landed costs:

The option rests on the following premise:

- Proximity with CGD networks in bordering Geographic Areas (GA) of India leading to prospects of access to Gas pipeline network of India in near future
- High population density, and consequently demand, in provinces bordering India
- Multiple small diameter pipelines, easy to lay for multiple demand nodes

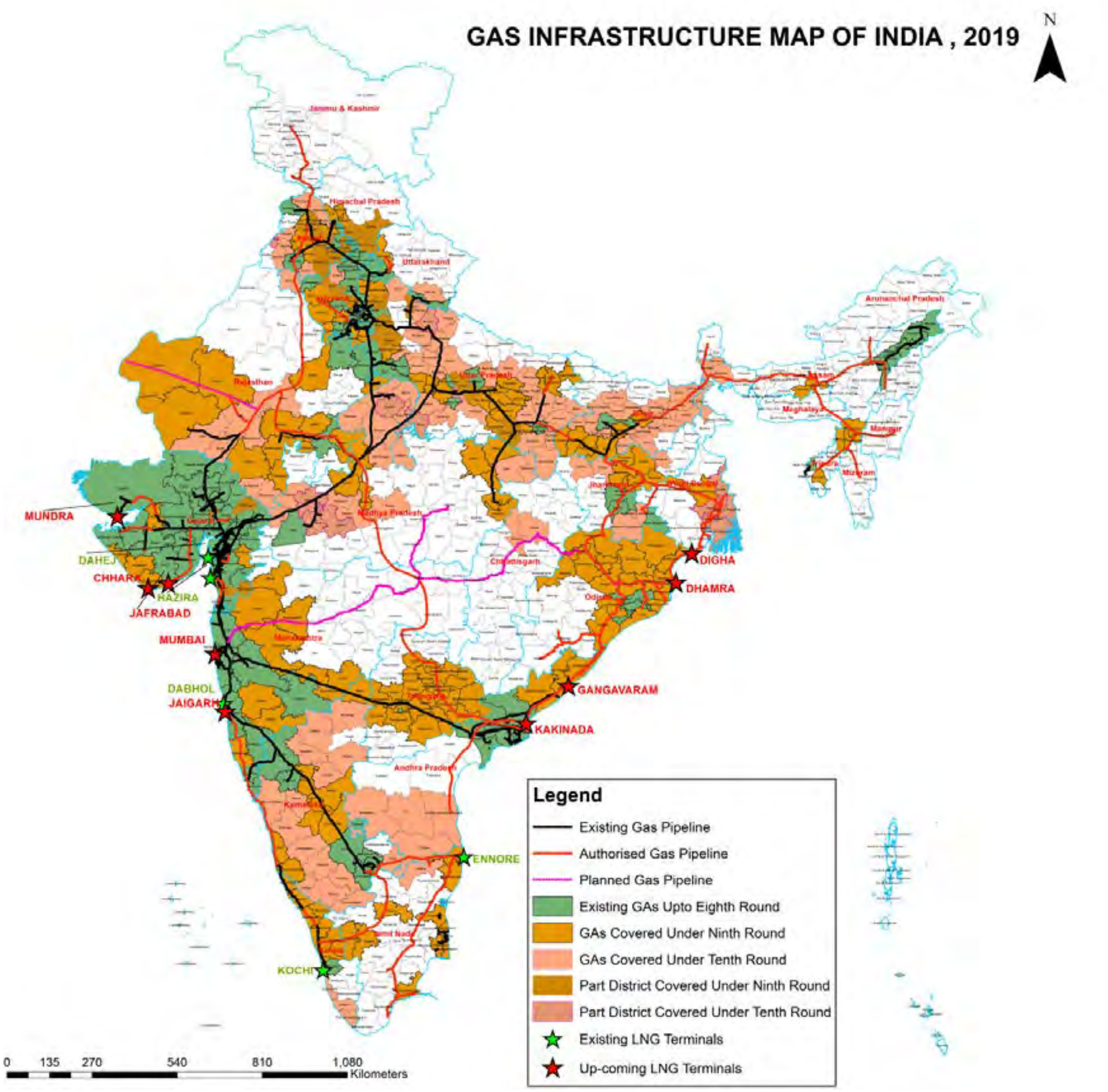
Brief analysis is as follows:

i) Proximity with CGD networks in bordering Geographic Areas (GA) of India

In the past few years, India has intensified the development of Gas pipeline infrastructure across the country along with development of the City Gas Distribution (CGD) network. The CGD network for a pre-determined Geographical Area is authorized to the highest bidder in a transparent bidding procedure in accordance with the regulations formulated by PNGRB, the downstream regulator. In the past two years, in the 9th and the 10th Bidding rounds, a large number of Geographical Areas have been successfully authorised by the PNGRB. As on date, nearly 70% of the India's population is covered in the authorised CGD networks.

Many of these authorizations of Gas are on the border areas with Nepal or in near vicinity. The map of GA authorised for CGD by PNGRB shows that Nepal is in close proximity on East, South-East, Southern with these networks being developed:

Fig-4.5.1: India's CGD Network: Geographic Areas being developed by different Authorised Entities



(Source PNGRB)

These CGD networks would be connected to the Gas pipeline grid of India in near future

(ii) Proximity of Provinces

Nepal has seven provinces comprising of total 77 districts. A map displaying the Provinces is illustrated in the figure below:

Fig-4.5.2: Nepal and Provinces

(Source:Wikipedea)

However, the population is not evenly distributed. Population density is more in the lower hills and the plains on the foothills, called the Terai region in the South and South-East. The other region with high population density is the Kathmandu Valley. Four out of the seven provinces are more densely populated, with a share of three-fourth of the total population. The key Industrial Clusters (Cement, Steel, Paper, Wood, Brick-kilns etc) are also located in these provinces. The distribution of population is as follows:

Table-4.5.2: Provinces of Nepal, Capital, Area and Population (Census 2011)

	Provinces	Capital	Area (sq kms)	Population
1	Province No 1	Biratnagar	25,905	45,34,943
2	Province No 2	Janakpur	9,661	54,04,145
3	Bagmati Pradesh	Hetauda	20,300	55,29,452
4	Gandaki Pradesh	Pokhara	21,504	24,03,757
5	Province No 5	Butwal	22,288	47,41,716
6	Karnali Pradesh	Birendranagar	27,984	13,27,957
7	Sudurpaschim Pradesh	Dhangadi	19,539	25,52,517

(Source – Wikipedea)

The capital cities of the four provinces with highest population and population density are all within 51 to 206 kms from India's CGD Networks being developed. The details like population, density, proximity with neghbouring GA of India's CGD, distance, Authorised Entities and the Bidding Rounds by PNGRB in which these authorizations have been awarded are reflected in the table below:

Table -4.5.3:Proximity and Multiple connectivity options propsed by Author for Nepal's Provinces with CGD Networks of India

Nepal - India Pipeline Connectivity Options							
Density of Nepal's Provinces Bordering India				Nearest Indian Geographical Area (GA)			
Province	Population	Density	Capital	GA	Distance	Licensee	CGD Round
Province 2	54,04,145	559.00	Janakpur	Madhubani, Darbhanga,	51, 79		11
Bagmati	55,29,452	272.00	Hetaunda	Motihari, Muzaffarpur	110, 206	IOCL	10
Province 5	44,99,272	219.00	Butwal	Gorakhpur	126	Torrent	10
Province 1	45,34,943	175.00	Biratnagar	Araria, Kishanganj	51	IOCL	10

Notes
1. Process for 11th Round initiated by PNGRB on 4.2.2020
2. Authorizations of 10th Round finalized by PNGRB in 2019

(iii) Laying multiple pipelines of small diameters

Instead of one trunk lines, this Option considers a number of small sized pipelines, which can be laid in shorter duration and provide access to gas supplies. The secondary network for Intra-Provincial / Inter Provincial can be developed later.

The following assumptions have been made by the author for estimating cost of the elements of the supply chain:

a. An upfront tie up of Term-LNG from the nearest LNG Terminal, i.e. Dhamra.

b. The DES prices have been assumed at Crude Parity of 12.5% in $/mmbtu. The cost have been worked out at Crude Prices at 40, 50 & 60 $/bbl.

c. Regasification and other costs at terminal (including Port Charges, Taxes & Duties) have been taken as 2 $/mmbtu.

d. The Pipeline tariffs for the Indian pipelines from Dhamra are yet to be finalized. They have been assumed as 1.5 $/mmbtu upto the take-off points in respective CGD Networks.

e. Pipeline of sub-12 inch size at medium to high pressures (45 - 95 Kg/cm2) can easily meet the requirement equivalent to 300 KTOE.

f. The cost of pipeline laying is derived from the contracts awarded by GAIL in 2016-17(@ INR 50-60 Millions/km for a 24-30 inch high pressure line) by discounting for Diameter and escalating at 5% per annum and for the difficult terrain.

g. Levelized pipeline tariffs, with margins, assumed as 0.5 $/mmbtu.

h. The distribution costs would include connecting spurs to nearby population along the route or from the capital cities of the province to nearby towns and highways.

i. The target segment are CNG Consumers, and PNG consumers from Industries, Commercial and Domestic consumers.

The landed cost for retail consumers works out between 13 to 15.5 $/mmbtu for markets with crude prices at 40, 50 & 60 $/barrel as in the table below:

Table-4.5.4: Landed price of gas in Option B (Multiple links with India's Gas pipelines for CGD Network)

Option B: Landed cost of LNG by Multiple links with India's CGD Network in adjoining GA			
A). Crude Prices (in $/bbl)	40	50	60
B) DES at Crude Parity 12.5% (in $/mmbtu)	5	6.25	7.5
C) Regasification and Other (in $/mmbtu)	2	2	2
D) Pipeline Tpt Costs: India (in $/mmbtu)	1.5	1.5	1.5
E) Costs for short links with India's CGD Networks in adjoining GA	0.5	0.5	0.5
F) Bulk Consumer Costs (B+C+D+E) (in $/mmbtu)	**9**	**10.25**	**11.5**
G) Retail Distribution Costs (in $/mmbtu)	4	4	4
H) Retail Consumers Costs (F+G) (in $/mmbtu)	**13**	**14.25**	**15.5**

Notes
1.Term contract prices are negotiable and downward prices can be explored
2. Liquefaction, Pipeline and Distribution costs can be higher if consumption is low

C) Option C: LNG Virtual Pipeline (Road Transportation)

Over the past decade, the popularity of road transportation of LNG in Container trucks retrofitted and equipped with capability to handle cryogenic liquids has grown all over the globe. In India, many cities in South India and other regions not connected by pipelines fulfil their demand by transporting LNG in this form. GAIL has recently commissioned the CGD for Bhubaneshwar by transporting LNG by road lorries equipped with cryogenic containment system all the way from Hazira, about 1,700 kms away.

The following assumptions have been made by the author to estimate landed cost of gas by 'Virtual' LNG supply:

1. An upfront tie up of Term-LNG from the nearest LNG Terminal, i.e. Dhamra or Proposed Kukrahati Terminal near Haldia.
2. The DES prices have been assumed at Crude Parity of 12.5% in $/mmbtu. The cost have been worked out at Crude Prices at 40, 50 & 60 $/bbl.
3. Other costs cover the Port Charges, Taxes etc.
4. Regasification at LNG Receiving terminals is not required and that cost is saved. It is incurred later at vapourisers at LNG delivery facility.
5. Road transportation for about 1100 kms from Dhamra @ 2.5 to 3 $/mmbtu as per the prevailing industry thumb rule rates.
6. Retail distribution costs are taken as about 3 $/mmbtu and includes Vaporization costs.

The landed costs work out to be about 13 to 15.5 $/mmbtu benchmarked with Crude prices from 40 to 60 $/bbl as follows:

Table-4.5.5: Landed cost of gas by Small-scale / Virtual LNG Supply Chain (Road Transportation)

Landed Cost of Gas by LNG Virtual Pipeline (Road Traansportation (in $/mbtu)			
A). Crude Prices (in $/bbl)	40	50	60
B) DES at Crude Parity 12.5% (in $/mmbtu)	5	6.25	7.5
C) Other costs	2	2	2
D) Road Transportation	3	3	3
E) Bulk Consumer Costs (B+C+D)	10	11.25	12.5
F) Retail Distribution Costs	3	3	3
G) Retail Consumers Costs (E+F)	13	14.25	15.5

Notes
1.Term contract prices are negotiable and downward prices can be explored
2.Transportation costs are for 1000 kms (Ex Dhamra), can come down from Kukrahati / Haldia
(Source: IRADe)

4.5.2 Analysis of the options: Comparing Pipeline vs Virtual mode of supply

The pipeline supplies and Small-scale / Virtual LNG Pipeline have their own merits and demerits. A comparision of the two modes has been tabulated as below:

Table-4.5.6: Comparing Supply Chain Options: Pipeline v/s Small-scale / Virtual LNG

Comparison of Pipeline and 'Small-scale / Virtual LNG Supply' (Road Transportation)		
Attribute	**Pipeline Transportation**	**Small-scale / Virtual LNG Supply / Road Tankers**
Capex	Capital Costs are high. Cost of a 12-inch pipeline can be upto 50 - 60 Million NR /km or upto 500,000 $/km	Capital Costs are less, about 5% of Pipeline Installation costs. There has been a reduction in costs of Vaporisers / LNG Storage Facilities. Excluding cost of land, the LNG Storage tank, Vapourisers and CNG Station costs less than 2 Million USD for a City-based facility feeding about 10,000 Kg/day.
Opex	Operating costs are less, nominal escalation with time.	LNG Road carriers are retrofitted to handle Cryogenic Cargoes and cost more. They have to be contracted on hire-lease basis and the operating costs are higher. The Operating cost of Vaporizer Station is also an additional cost. These costs escalate with time.
Economies of scale	Pipelines are economical when they operate near to their capacities. Accordingly, the through-puts have to be worked out upfront to plan for the size and operating pressures of the pipeline.	The capacity is scalable. And as demand rises, another vaporiser of required capacity can be added. Besides, there is flexibility in physical locations of future expansions, depending on demand and availability of land.
Risks: Take-or-Pay, Ship-or-Pay obligations.	Pipelines operate at nearby their design capacity. It requires firm supply quantities or 'Term - LNG' contracts, booking of adequate Regasification capacity and 'Contract Carrier; capacity in Pipeleines. Hence, 'Take-or-Pay' and 'Ship or Pay' charges for booking 'Term LNG' or 'Contract Carrier' capacities is a potential risk if adequate demand does not generate and off-take are less than the Minimum quantities for Take-or-Pay / Ship-or-Pay	More flexibility in tie-up of 'Term' and 'Spot' Cargoes. More flexibility in reselling the contracted quantities and transporting them utilizing the Transporation Contract, and thereby, mitigating risk of minimum 'Take-or-Pay' charges. However, volatility of LNG Spot prices in tight supply scenario is a potential cost risk, which can be mitigated at hedging cost. Ship -or-Pay risks do exist for the LNG Road Lorries. This can be done away by owning the fleet or reselling cargoes to other buyers. Another risk is the loss of cargo as boil-off during transportation. But this too can be mitigated by utilizing LNG-fuelled engines for the Lorries, which utilize the Boil-off.

Project Implementation		
a) Completion time	6 to 7 Years: Upto two years are required to process all approvals, clearances, permissions from statutory/municipal/state authorities. Time for acquiring ROW /ROU is also quite long. Further, pipeline laying, testing and commissioning also takes 2-3 years.	Can be started in 2 years. One year for Pre-Enginnering and placement of award/contract for the Storage Tank and Vaporisers at Receiving end. One year for completing the construction and commissioning of the facilities. One year is also required to order the Contract for Cryogenic Tankers.
b) Complexity	High Complexities: Risks and constraints of steady cash flows, delays and cost escalation in execution, require very tight monitoring and quick decision making.	Low Complexities: Risks are comparitively less at LNG Receiving end. Risks are only in road transportation.
Overall Assessment	Initial costs are high, Time required to commence supplies is more, 'Take-or-Pay' risks are higher for demand less than the contracted quantities.	Initial costs are less. Operations can commence in 2-3 years. More Flexibility in mitigating risks like 'Take-or-Pay', by re-selling and transporting quantities elsewhere under contract for LNG tankers /lorries. But road transportation costs escalate much more than escalation in pipeline tariffs.

(Source: IRADe)

To summarize, there are some merits in 'Virtual' mode. Initial costs are less. Operations can commence in just 2-3 years. This option is ideal for small volumes of say 10,000 kg/day for a receiving station. The scalability can be by installing additional storage or multiple stations at an appropriate demand centres, thereby pre-empting need for laying interconnecting pipelines. More Flexibility in mitigating risks like 'Take-or-Pay', by re-selling and transporting quantities elsewhere under contract for LNG tankers / lorries. . To summarise, 'Virtual' mode has some distinct benefits

- Initial capital costs are less.
- Operations can commence in 2-3 years, pipelines take at least 4-5 years or more to be laid
- This option is ideal for small volumes of say 10,000 kg/day for a receiving station. Benefit of choosing multiple locations in proximity with consumer base.
- The quantities can be can be scaled up later to the desired capacity.
- Flexibility in despatch schedules to supply destinations, hence, better utilization of the fleet.
- More Flexibility in mitigating risks like 'Take-or-Pay', by re-selling or diverting and transporting quantities elsewhere under contract for LNG tankers /lorries

The demerit of 'Virtual' mode is that over mid to long-term, escalations in road transportation costs are much more than the escalation in RLNG pipeline tariffs.

4.5.3 Estimating potential gains on switching to gas

Prior to investing and switching to a new energy source, the policy makers compare the economic advantage in the long-run, volatility in prices, assured availability or energy security with the existing energy sources. Besides, the consent and conviction of the consumer is a key enabler for accelerating the switch over.

Bhutan is an electricity surplus nation. Its power sector is entirely on Hydropower save for some small capacity of DG sets. The author has analysed the cost economics of the of fossil fuels and compared it with the estimated cost economics of gas supplies as worked out in the 5.5.2 above.

The methodology adopted is:

- Determine the Specific cost of thermal energy in for the existing petroleum products
- Compare it with that of gas supplies
- Ascertain the potential gains for switching the existing energy options to gas,

A) Specific Cost of LPG, Petrol & Diesel at prevailing prices (as on 1.4.2020):

Prior to investing and switching to a new energy source, the policy makers compare the economic advantage in the long-run, volatility in prices, assured availability or energy security with the existing energy sources. Besides, the consent and conviction of the consumer is a key enabler for accelerating the switch over.

Nepal is an electricity surplus nation. Its power sector is entirely on Hydropower and imports via CBET. The author has analysed the cost economics of the petroleum fuels, LPG and COAL; and, compared it with the estimated cost of gas supplies as worked out in various options at 4.5.2 above. The specific cost of thermal energy at prevailing prices are about 24.4 $/mmbtu for petrol, 19.4$ /mmbtu for diesel, 17.1 $/mmbtu for LPG and 7.9 $/mmbtu for coal.

Table-4.5.7: Specific cost of thermal energy in LPG, Petrol and Diesel in Nepal

Fuel	Price	Unit	GCV	Unit	Price In NRs/1000 Kcals	Price In USD/mmbtu
LPG (14.2 kg Cylinder)	1375	NRs/Cyl	11,900	Kcals/Kg	8.1	17.1
Petrol	96	NRs/Litre	8269	K cals/litre	11.6	24.4
Diesel	85	NRs/litre	9185	Kcals/Litre	9.3	19.4
Coal	15	NRs/kg	4000	kcals/kg	3.8	7.9

Notes
1. GCV of Petrol is 11,100 Kcals/Kg and density is 0.745 Kg/litre
2. GCV of Diesel is 11,000 Kcals/Kg and density is 0.835 Kg/litre
3. GCV of CNG is 10,000 Kcals/cubic metre or 12,500 Kcals/kg
4. GCV of LPG is 11,900 Kcals/kg
5. Exchange rate is 1 USD = 120 NRs
6. Conversion from Kcals to btu: 1 K cal = 3.966 btu

B) Comparing Specific Cost of thermal energy in the existing fuels with the landed cost of gas in the Supply Options 'A', 'B' & 'C'

The prevailing pricing of the petroleum products and coal have been compared with the approx landed cost of Natural Gas by Pipeline (as in Options A & B) and Small-scale / Virtual LNG supplies (as in Option C). The cost saving is about 40% for substituting Petrol and about 20% by substituting Diesel with Gas Supplies via Small-scale / Virtual LNG Supply mode as in the table below:

Table-4.5.8: Specific costs of thermal energy in Gas Supplies in Options A,B & C with LPG, Petrol, Diesel & Coal (Author's assumptions)

Specific cost of thermal energy in Coal, Petroleum products with Natural Gas in Nepal						
Fuel	**Price**	**Unit**	**GCV**	**Unit**	**Price In NRs/1000 Kcals**	**Price In USD/ mmbtu**
LPG (14.2 kg Cylinder)	1375	NRs/Cyl	11,900	Kcals/Kg	8.1	17.1
Petrol	96	NRs/Litre	8269	K cals/litre	11.6	24.4
Diesel	85	NRs/litre	9185	Kcals/Litre	9.3	19.4
Coal	15	NRs/kg	4000	kcals/kg	3.8	7.9
Option A: Regasified LNG by dedicated Pipeline						15 to 17.5
Option B: Regasified LNG by multiple short links with Indian CGD Network in adjoining GAs						13 to 15.5
Option C: Small-scale / Virtual LNG Supply Chain (By Road)						13 to 15.5

Notes
1. GCV of Petrol is 11,100 Kcals/Kg and density is 0.745 Kg/litre
2. GCV of Diesel is 11,000 Kcals/Kg and density is 0.835 Kg/litre
3. GCV of CNG is 10,000 Kcals/cu metres or 12,500 Kcals/kg
4. GCV of LPG is 11,900 Kcals/kg
5. Exchange rate is 1 USD = 120 NRs
6. Conversion from Kcals to btu: 1 K cal = 3.966 btu

While the estimated prices of gas and LPG are nearly same, there is a distinct benefit of about 40% in case of petrol and 20% in case of Diesel.

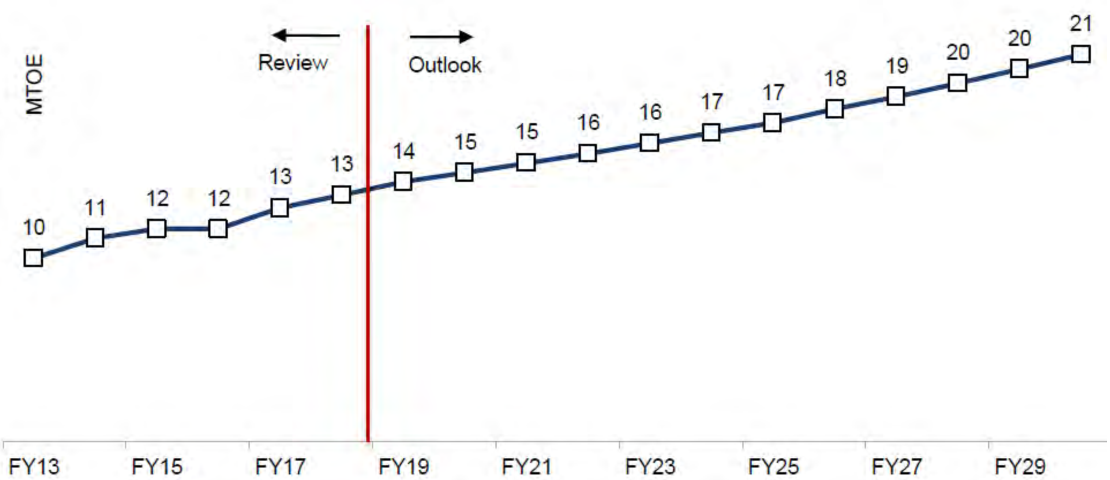
4.6 Gas demand estimation

4.6.1 Key economic drivers

A) Growth forecast of Primary Energy:

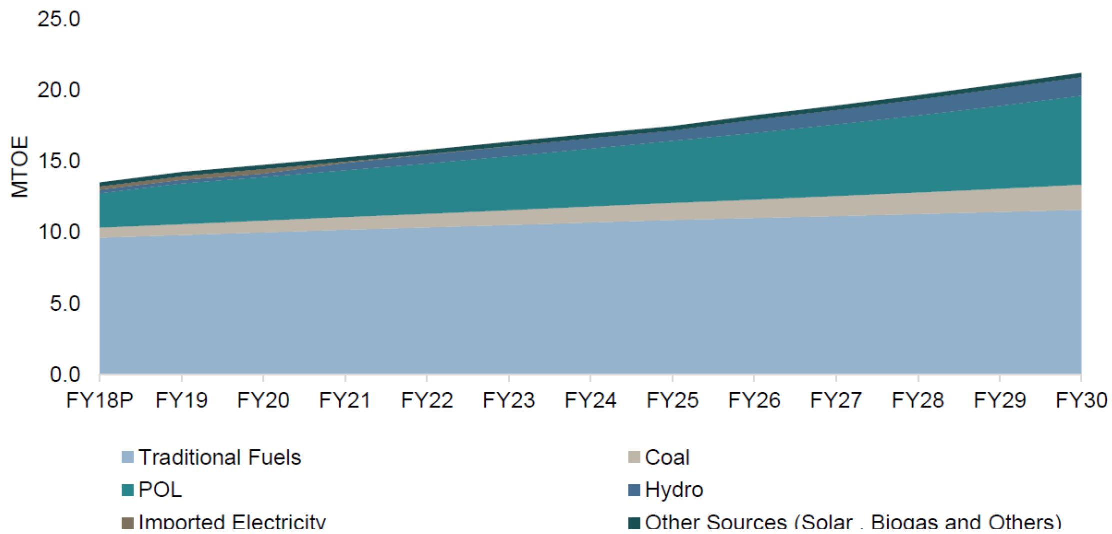
Nepal's primary energy is expected to grow at CAGR of 3.8% from 2018 to 2030, and its primary energy consumption is likely to reach 21.2 MTOE by Fiscal 2030 (Refer Fig below)

Fig-4.6.1: Forecast of Primary Energy and share of energy Source



(Source: SAARC Energy Outlook 2030 / CRISIL)

Fig-4.6.2: Forecast of share of energy source



(Source: SAARC Energy Outlook 2030 / CRISIL)

C) Environment protection and Climate Change

The country is dependent on hydropower for about 99% of its own generation. The capacity utilization of these plants depends upon the hydrology of the river systems. Climate chane threatens to adversely impact the water flows in the river systems. Therefore, reduction of GHG gases is an important concern for Nepal. Natural Gas has lower GHG emissions as compared to Diesel & Petrol. Besides, the country would look forward to improve the penetration of LPG for cooking in the households. This would help to conserve forests and also lower emissions.

4.6.2 Sector-wise demand projections:

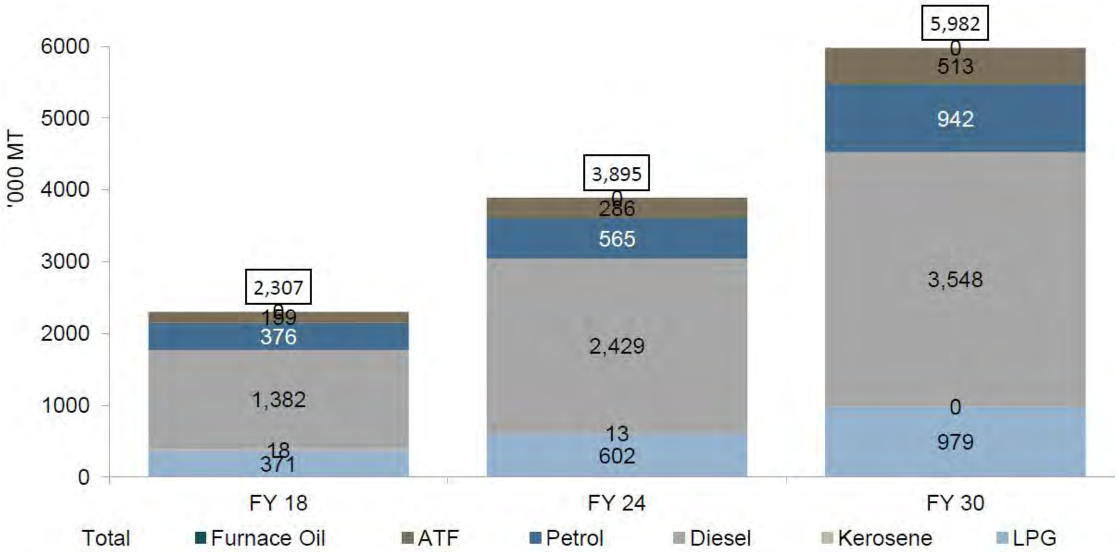
The projection of demand would depend upon the following factors:

- The growth in demand of fuels which gas could substitute
- The level of penetration during substitution

A) Growth in demand of Fuels:

As discussed at Para 4. The GDP is expected to grow at 4.5 to 5 % from 2019 to 2030. While the Primary Energy is expected to grow at around 3.8%, the growth of petroleum products and LPG will be dissimilar and much higher. Thegrowth in petrol is backed by about 7.8% growth in passenger vehicles (2, 3 & 4-wheelers), in the coming years. Petrol is likely to grow at a CAGR of 8%. Diesel is consumed by transport (80%) and industries (11%). The growth in demand for diesel is backed by growth in these sectors and is likely to grow at 8.2% through 2030. The LPG sector witnessed a steady growth of 12% in the past, and is expected to grow at 8.4% . The expected growth in KT is likey to be 3,895 KT in 2025 and 5,982 KT in 2030 (Refer Fig below)

Fig -4.6.3: Growth of Petroleum Consumption



(Source: CRISIL SAARC Energy Outlook 2030)

B) Estimating the level of Penetration / Substitution

The expected demand projections for various petroleum products are exhibited in Table ….Above. The switching or level of substitution for different fuels by gas will depend upon the arbitrage, availability, accessibility and Government policy initiatives.

The level of penetration has been done by identifying the candidate segments and analysing the factors which can influence the switching to gas.

i) Candidate segments:

The power sector records insignificant generation from HFO/Diesel/ Coal, and there are no plans to add any thermal power plant. As such, there is little scope of any consumption of gas in this sector.

The transportation sector consume Petrol and Diesel, which have a price arbitrage of 40% and 20% respectively on switching to gas. The industries use bulk quantities of Diesel, and the arbitrage for switching to gas for bulk supplies is about 30-40%. The household sector consume LPG. Substitution of LPG can also be considered for the convenience and ease in handling by domestic and commercial consumers.

ii) Estimating Fuel wise penetration

The following assumptions have been made for working out likely substitution quantities:

1. **Petrol:** The about 40% price advantage of gas over petrol will drive the penetration. Exxonmobil has predicted that the global rise of CNG-vehicles shall be around 4.5% p.a. In India, CNG is gaining popularity and some ripple effect of consumer behaviour is also expected to permeate across the border in Nepal. However, the demand shall pick up slowly. As such, only 10% of switch by FY 2024, and 20% by 2030 and thereafterhave been considered.

2. **Diesel:** The rise in PM10 levels in Kathmandu other cities is causing serious environmental concerns and are likely to result in stringent measures like ban of Diesel for passenger vehicles and taxi. The substitution has been considered as 5% in 2024 and 15% in 2030. Industries comprise of about 11% of the total consumption. The Industries provide good volumes and returns for the CGD operators. They are likely to gain access on priority. Owing to the prolonged hours of power cuts, particularly during dry season, DG sets have become prevalent and switch to gas could be as high as 75%. The remaining 9% is consumed by commercial / others. For them, the switch has been taken as 50% in 2024 and 2030.

3. **LPG:** While there is minor cost advantage on gas over LPG, consumers prefer the convenience and safety of using piped supply. However, penetration is constrained by the difficulties in providing access to all household consumers. Accordingly, switch has been assumed as 15% in FY 2024 and 30% in FY 2030.

Coal: Specific cost of thermal energy in Coal is cheaper than gas. However, some consumers have to shed out premium on their coal purchases and gas could just about meet their requirement in an economic manner. There are some small consumers who would prefer clean fuel like gas. Stringent pollution norms could also be the reason for some switch over of say about 5% in FY 2024 and 10% in FY 2030.

The penetration of gas, as discussed above, has been tabulated in the Table Below:

Table-4.6.1: Summarizing Penetration level of gas by switching of fuels

Summarizing level of penetration of gas by switching of fuels					
Fuel	**Cost Benefit in %**	**Level of Penetration**			
		2025	2030	2035	2040
Petrol	40%	10%	20%	20%	20%
Diesel	15% – 20%				
Transportation (80%)		5%	15%	15%	15%
Industries (11%)		75%	75%	75%	75%
Others (9%)		50%	50%	50%	50%
LPG	Nil	15%	30%	30%	30%
Coal	Nil	5%	10%	10%	10%

(Author's assumptions)

4.6.3 Demand Summation

Based on the above analysis of the demand for fuels and level of penetration, the likely substitution of Petrol, Diesel, LPG and coal by LNG emerges between 0.53 MTPA in 2025 to about 2.73 MTPA in 2040 as illustrated in the table below:

Table-4.6.2: Estimated penetration of Gas in Energy Basket of Nepal between 2025 to 2040

Gas Penetration in Energy Consumption										
	2018	**2025**			**2030**			**2040**		
	Consumption	Quantity	Level of Substitution	Eq Gas Quantity	Quantity	Level of Substitution	Eq Gas Quantity	Quantity	Level of Substitution	Eq Gas Quantity
A) Petrol	376	585	10%	59	942	20%	154	2,034	20%	334
B) Diesel	1,382	2,429		334	3,548		720	7,840		1,419
a) Transport	1,106	1,943	5%	80	2,838	15%	349	6,720	15%	827
b) Industry	152	267	75%	164	390	75%	240	648	75%	398
c) Others	124	219	50%	90	319	50%	131	473	50%	194
C) LPG	371	602	15%	90	979	30%	294	2,193	30%	658
D) Coal	1,198	1,892	5%	47	2,985	10%	149	6,444	10%	322
Total				530			1,318			2,732

Notes
Petrol & Diesel in thousand KL, Coal in thousand MT, LPG in thousand MT, Gas in thousand MT
The estimated gas consumption has factored in the equivalent gas for different types of fuels.
(Author's assumptions)

4.6.4 Analysis of gas demand, supply options

After considering the three options of gas supply logistics, the expected demand volumes and analysing the city-wise demand, exploring Option 'C', (Small-scale / Virtual LNG Supply Chain with Storage Tanks and Vaporizers of appropriate capacity) appears to be the best way to begin with. The 'Virtual' mode has been successfully deployed in India. As their market develops, the capital costs of Lorries equipped with cryogenic containers and their operational costs are likely to decline over a period of time. Transportation solutions like 'wet lease', 'time charter' or 'trip hire' may evolve over the time providing more efficiencies, flexibility and cost reduction.

4.6.5 Growth of Gas: Key challenges and enablers

Some of the key challenges are as follows:

Electric Vehicles: The increases accessibility of electricity is a motivating enabler for the growth of Electric Vehicles. But, the higher costs and low per capita income are the key road blocks. Further, the prolonged hours of power cuts are also a dampener. Till such time Nepal successfully commissions a adequate storage type hydropower capacity, round-the-clock availability of power in dry season will always be big question mark.

The key enabler is the government policies and support. Key enablers are

Taxes: Providing a low tax structure would help to keep the gas prices beneficial for the consumers. India, the neighbouring country has a lower tax structure for Natural gas as compared to Petrol & Diesel, and is planning to further reduce the taxes.

Revising emission standards: The release of GHG gases and pollutants by Diesel and Firewood/ Biological fuels are contributors in Climate Change / Global Warming. Thes pollutants also pose greater health hazards for citizens. Neighbouring countries like India & China are already struggling to keep the pollution levels below hazardous levels. Above all, Nepal's economic development is anchored on the growth of its Hydropower. Climate change can lead to decline in glaciers and the rainfall, thereby adversely affecting its growth. Gas has lower carbon footprints and is less hazardous. Stringent measures and control on emissions by reducing Diesel & Firewood in preference to gas could pay rich dividends for economic growth and health of citizens.

4.7 Summary of Key Drivers for growth of Bhutan's Gas Sector

1. Limited Potential

Primary energy consumption itself is only about 14 MTOE and is expected to grow to 17 MTOE in 2025 and 21 MTOE in 2030. Nearly 71% is sourced from firewood, agriculture residue and animal dung. The Power Sector is dependent on Hydropower and do not need any gas.

Petroleum and Coal sectors have limited consumption and demand is limited to less than 5 MTOE in 2024 and le than 8 MTOE in 2030.

Table-4.7.1: PROJECTED GROWTH OF FUELS (In KT)

FUEL	FY 2017	FY 2024	FY 2030
Petroleum Products	1,924	3,895	5,982
Coal	1,127	1,892	2,985

Note: Petrol, Diesel and LPG constitute 90% of Petroleum Products.

As such, the volumes of penetration of gas are limited.

2. Opportunity

The pricing of petroleum products do provide the cost-saving opportunity for Petrol and Diesel consumers to switch to gas. The authorizations awarded to entities for implementing City Gas Distribution (CGD) network in bordering areas with Nepal spring opportunity of realizing gas pipeline connectivity in these regions. These districts of Nepal are not only densely populated but also the hub of main industrial and commercial activities. Eighteen of the twenty most populous cities are in these regions. This is seen as an opportunity for penetration of gas.

3. Options

The increasing popularity of Small-scale / Virtual LNG Supply chain, comprising of LNG supplies by road trucks equipped with cryogenic cargo containment and LNG Storage and Vaporizers at points of end use, has come a long way in easing access to LNG in far flung areas not connected by pipelines at competitive prices. Nepal's cities are within 1,000 – 1,100 kms of Dhamra LNG terminal, and can explore this supply chain option for direct supplies to its cities.

4. Policy Initiatives

The country's generation is largely dependent on Hydropower. Besides, substantial capacity addition is already under implementation huge investments have been done. Hydropower projects support the cement, steel manufacturing, fabrication, engineering and related industries in a pivotal manner. Climate change can seriously impact the hydrology of the rivers of Nepal. With a technically-feasible potential of about 34 GWs remaining to be exploited, addressing Climate Change and measures for tighter control of GHG is of utmost priority. Tighter environment norms and reducing dependence on Forest Firewood for energy would have to be curtailed. This requires serious policy measures from the government. Gas, clean fuel offers environmental benefits and can help in mitigating GHG emissions with political support and interventions.

Turquoise P FSRU - Courtesy of Pardus Energy

Chapter 5: Growth Potential for Bhutan's Gas Sector

5.1 Key demographics of the Energy sector

Bhutan is a small land locked country of about 38,000 sq kms, situated between India and China. It has a population of just fewer than 800,000. The country practices monarchy and is in transition state for migrating to democracy. Its previous monarch, who ascended the throne in 1974, intensely pursued the implementation of the Five-Year plans and launched a steady course of development in farming, processed fruits, alcoholic beverages, tourism, animal husbandry and wood products. His intense interactions with the public helped in governance and growth. The GDP growth of the country has been around 7.5% pa since the early eighties. Besides, economic ties with India were strengthened with the development of hydropower projects to power the economy. The country's governance is known for its unique objectivity in 'Gross National Happiness' as the key index of development.

Bhutan's per capita GDP was 3423 $ in 2018. The growth came down in 2018 to 4.5%. About 58% of its GDP is contributed by Industry and Agriculture and remaining from Services. The unemployment rate is about 3.4%, but it is 15.7% amongst youth (15 – 24 yrs), and a key issue of concern.

Primary Energy Consumption

Bhutan's total Primary Energy consumption in 2018 was only about 744 KTOE. The largest source of energy is Bio-mass, which has a one-third share of its Primary Energy consumption. Hydrocarbons meet about 41% of its energy need, with coal and petroleum products have share of 18% and 23% respectively. The shares of different sources of energy are as follows:

Table-5.1.1: Bhutan's Primary Energy Consumption

Source	Share (in %)
Bio Mass	33
Major Hydro	26
Petroleum	23
Coal	18
Renewables Energy & Others	1

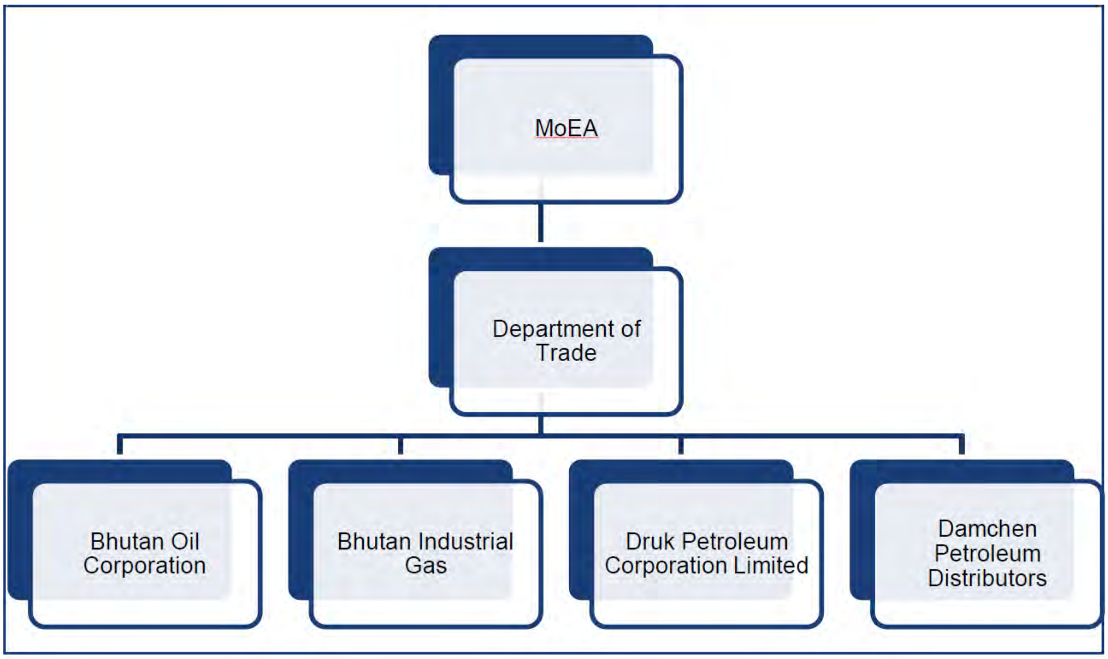
Source: SAARC Energy Outlook 2030, CRISIL

The country is rich in Hydropower resources. It has collaborated with India to exploit its hydropower resources. In 2018, Bhutan exported about two-thirds of its power to India after meeting its full requirement. Bhutan's per capita electricity consumption is over 2800 kwhr, the highest in the BBINS region. Almost everyone in Bhutan has access to electricity. It is a 'carbon negative' nation. Nearly 70% of Bhutan is covered by forests and 8% of its lands are permanently covered by year-round snow and glaciers. Yet, about 95% of the population have piped water supply.

5.2 Organogram of the Oil & Gas sector.

The country does not have any Oil or Gas deposits / reserves. The petroleum products are imported from India and distributed across the country under control of the government. All operations are overseen and controlled by the Department of Trade under Ministry of Economic Affairs (MoEA). The MoEA governs three key departments for its energy policies. The Department of Energy is all policies and planning of its power sector including Renewable energy. The Department of Trade (DoT) oversees the import of oil and petroleum products and their distribution. An organogram of the oil & gas sector is as follows:

Fig -5.2.1: Organogram of the Petroleum Sector



(Source:SAARC Energy Outlook 2030 / CRISIL)

The Department of Geology and Mines control all mining operations for extracting minerals including coal.

5.3 Regulatory environment and policies in petroleum sector

5.3.1 Upstream:

The Department of Geology & Mines operates under the DoT and oversees the exploration of mineral wealth. However, Bhutan does not have any petroleum or gas reserves nor any refinery. The country imports its entire requirement of refined petroleum products (Petrol, Diesel, ATF, LDO, Kerosene, Bitumen) and LPG from India.

5.3.2 Downstream: Petroleum

The procurement of petroleum products are tied up by State Trading Corporation of Bhutan (STCB) on behalf of the DoT with NOCs of India (Indian Oil & Bharat Petroleum). Petrol, Diesel and Bitumen comprise of about 16% of the imports. The products are distributed by privately held companies, Bhutan Oil Corporation, Bhutan Industrial Gas, Druk Petroleum Corporation Ltd and Damchen Petroleum Distributors. Of late, Hindustan Petroleum (HPCL), another NOC of India, too has been permitted to commence petroleum retail operations.

Petroleum Pricing & Subsidies

The pricing of all petroleum products, except LPG and Kerosene, are priced as per the cost of imports and its transportation costs to various districts or dzongkhags. The Petrol & Diesel for exports from India do not invite Excise and other State taxes, which are as high as about 55 – 60% of retail costs in India. As such, Bhutan procures petrol, diesel and other petroleum products at a reasonable price. The taxes and duties applicable on import of Hydrocarbon fuels are as follows:

Table-5.3.1: Structure of Duties/ Taxes on Import of petroleum products and coal.

Type of Fuel	Duty	Sales Tax	Green Tax
Motor Spirit (Gasoline)	20%	5%	5%
Spirit Jet Fuel (ATF)	20%	5%	
HSD (Diesel Oils)	20%	5%	5%
Kerosene (SKO)	20%		
Kerosene Jet Fuel (ATF)	20%		
Coal	10%		

Source: SAARC Energy Outlook 2030 / Bhutan Trade Classification and Tariff Schedule (2017)

In spite of the above tax structure, the retail prices of petrol and diesel are about 20-25% cheaper than in India.

Bhutan receives an annual quota of 8,400 MT of subsidized LPG from India. The subsidy is nearly 60%. Over the years, the consumption has gone up and there remains an ever existing shortage of Subsidized LPG cylinders. However, India has not agreed to raise the quota. India continues to supply Unsubsidized cylinders, which is about more expensive by about 300 -350 Nus, as per the demand.

The Bhutan's government has made several initiatives to introduce Non-subsidized LPG for the Commercial consumers, but it has not been successful. The demand is only for the subsidized domestic LPG and the Non-subsidized LPG cylinders sell very low volumes. The department has now put a ceiling of one subsidised cylinder per month for household consumers.

Bhutan also receives an annual quota of 15,000 KL of subsidised Kerosene at about 75% subsidy from the Indian Government.

5.4 Analysis of the key energy sectors

5.4.1 Power sector

(A) Existing capacity:

i) Hydro Power Plants: Bhutan has a potential of about 30,000 MW of Hydro Power, out of which, about 23,760 MWs is techno-economically feasible to be harnessed. While the major generating capacities are the Hydro Power Plants, Bhutan also generates some power on DG- Sets and has also installed Wind Turbines. The country has an installed capacity of 2326 MW as in Mar 2020.. The Peak demand in 2018 was about 399 MW. As per BPC Annual Report, the country consumed about 2481 MUs, which also included about 19 MUs from DG Sets and less than 1 MU as import from Assam / India.

Key installed capacities of Hydropower with the year of commencement of operation are as in the table below:

Table -5.4.1: Key Generation capacity of Hydropower

List of Operational Hydro Power Plants (HPP) in Bhutan		
Name of Plant	Capacity in MW	Year of Opertaion
Chukha HPP	336.00	1998
Kurichhu HPP	60.00	2002
Basochhu HPP (I & II)	64.00	2005
Tala HPP	1020.00	2007
Dagachhu HPP	126.00	2015
Mangdechhu	720.00	2019
Total	2326.00	

(Source: BEA /Authore)

ii) Other Renewables (Solar and Wind): The country's installed capacity of Solar and Wind energy as in 2019 was only about 9 MWs. As per the available data, the solar irradiation is better than many parts of the world, including UK & Germany. Bhutan has prepared a Renewable Energy Master Plan – 2016 for exploiting its Renewables other than Hydropower.

iii) DG – Sets: Bhutan has an installed capacity of about 9000 KVA of DG Sets

B) Generation, Consumption and Export (Cross Border Trade)

As per the BPC Annual Report, net generation in 2018 was 6,919 MUs. The Transmission losses were about 2.15%. Out of this about 2492 MUs were supplied for domestic consumption, an increase of about 6.5% over previous year. The rest (4,437 MUs) were exported to India, which were about 15% lower than previous year exports of 5,306 MUs. Till 2018, Bhutan has been exporting about 70% of its power generation to India after meeting its requirements. The generation in 2018 was the lowest in a decade, primarily due to poor hydrology in its river systems. The low generation effectively led to a drop of exports to India. In 2019, after the commissioning of the Mangdechhu HPP (720 MW), the exports are likely to increase and will reflect in the existing and coming years.

The Industries consume nearly 78% of the electricity. The share of Buildings is about 20%. Buildings include residential, institutional and commercial. Residential segment consumes about 55% of the electricity supplied to Buildings. The rest is consumed by Agriculture and others. In 2018, the overall consumption of electricity grew by 6.5%.

C) Transmission & Distribution

The transmission and distribution network enables nearly 98 % of its citizens to have access to electricity. The transmission losses (or wheeling losses) are about 2.27% and T&D losses are only about 6.15%. Bhutan has provided nearly 100% access to its population.

D) Electricity Tariffs

The domestic electricity tariffs are determined as per the guidelines of 'Domestic Electricity Tariff Policy – 2016', issued by the MoEA. The guidelines consider a rationalized subsidy mechanism to enable affordable electricity to all domestic consumers, Low Voltage (LV), Medium Voltage (MV- 6.6/11/33 KV)) and High Voltage (HV- 66kv& above).

The distribution cost is high due to the terrain and low population density. In 2016, the distribution costs were 4.22 Nu/Kwhr for the LV consumers, 3.79 Nu/Kwhr for the MV consumers and 0.64 Nu/Kwhr for the HV consumers. A substantial subsidy has been provided for the LV & MV consumers, with an objective to improve the quality of life of the citizens.

The tariffs declared by BPC for a 3-year term (2020-2022) are enclosed at Annexure – 1 .They are about half to a third lower than the tariffs in India. Salient features of tariffs are:

i) **LV Consumers:** For Rural and Highlands residents, 100 & 200 units (Kwhr) are free and subsequent are charged at a nominal 1.28 Nu / unit. However, tariffs go up in blocks of higher consumption. For Bulk LV consumers, tariffs are at a flat 4.06 Nu/Unit. Bhutan has only 778 LV Bulk consumers

ii) **MV Consumers:** The tariffs are @ 2.24 Nu/Unit and in addition there is an additional Demand charge of 325 Nu/KVA. The average tariff was just 3.83 Nu/Kwhr prior to the period. There are 63 nos. of MV Consumers

iii) **HV Consumers:** Tariffs are only @1.5 Nu/Unit, an additional demand charge of 292 Nu/KVA and Wheeling charge of 0.27 Nu/Unit are also payable. The average tariff was just 2.23 Nu/Kwhr in the previous tariff period. There are only 16 HV Consumers in Bhutan

E) Growth projections of generating capacity:

Bhutan is implementing substantial generating capacity additions, mainly hydropower projects and also other Renewable Options (Solar & Wind) for its capacity additions. It is likely to remain a power surplus state in the next two decades. Sector-wise capacity addition plans are as follows:

I) Hydropower: About 2,758 MW of capacity, as in Table below, are under construction:

Table-5.4.2: Key Hydropower capacity addition under implementation

List of Upcoming Hydro Power Plants (HPP) in Bhutan		
Name of Plant	Capacity in MW	Expected Commissioning
Nikachhu	118.00	Jul-20
Punatsangchu- II	1020.00	Jun-21
Punatsangchu- I	1020.00	Jun-22
Kholongchu	600.00	Jan-27
Total	2,758.00	

(Source: BEA / Author)

ii) New Renewables (Solar and Wind): The country's solar irradiation is better than that in many parts of the world, including UK & Germany. The Renewable Energy Master Plan – 2016, claims a potential of about 12 GWs of Solar Energy and about 760 MWs of Wind energy. The country has targets to raise its capacity to 20 MWs by adding 5 MWs of Wind, 5 MWs of Photovoltaic Solar in addition to 3 MW equivalent of Solar heating systems.

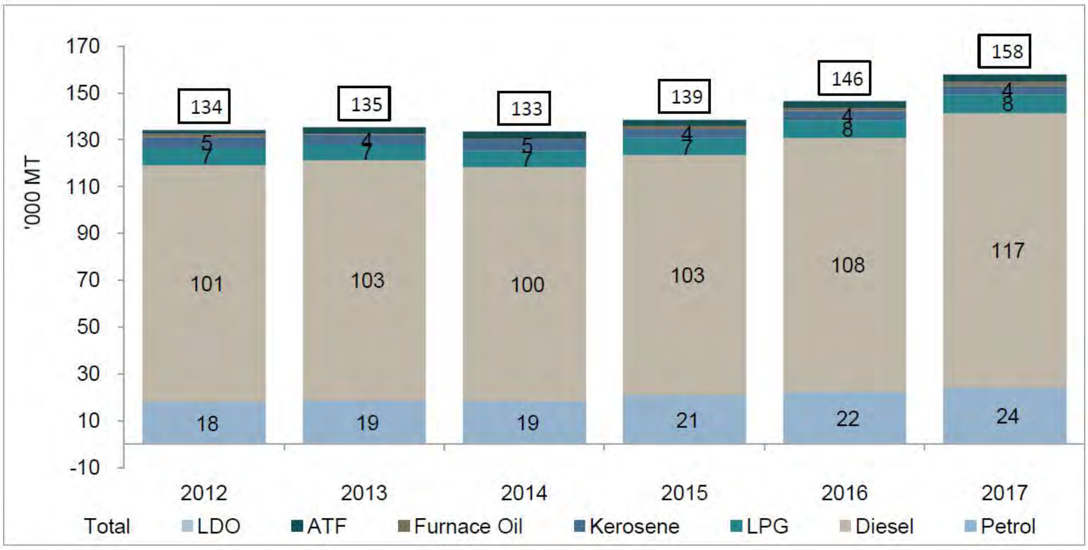
F) Growth projections of Electricity demand:

The outlook for growth in demand is about 8%. The Industrial growth rate is expected to be around 9.3%, whereas, the growth rate of Buildings / New Construction is expected to be about 7.2% pa. The growth of generating capacity is likely to boost exports as well as domestic demand and consumption.

5.4.2 Petroleum Sector:

A) Consumption: The petroleum consumption has been growing as the number of automobile sales have increased over the last two decades. The sales are also a function of the petroleum prices which vary in tandem with the global prices. The consumption of petrol has increased by 50% between 2012 and 2017. The consumption of petroleum products is mapped in the figure below:

Fig-5.4.2: Consumption of Petroleum Products between 2012 – 2017



(Source SAARC Energy Outlook 2030/ CRISIL)

In 2018, the consumption had grown further to approximately 173,000 MT. The entire quantity was imported from India. As per the Statistic Yearbook 2019 of Bhutan Government, imports in 2018 including LPG and Bitumen were as follows:

Table-5.4.3: Import of Petroleum Produts in 2018.

Petroleum Imports in 2018		
Fuel	KL/MT	Quantity
HSD	KL	159, 722
Petrol	KL	46,912
Kerosene	KL	3,585
Aviation	KL	4,878
FO	KL	3,410
LPG	MT	8,702
Bitumen	MT	25,745

(Source: DOT, Bhutan)

Source Statistics Yearbook of Bhutan 2019, Bhutan Government

B) Petroleum Pricing

Petrol & Diesel: The petroleum products are imported from India. They are subject to an import duty of 20%. Petrol and Diesel are subject to 5% Sales Tax and %% Green Tax.

LPG: LPG is imported from India. Bhutan has a quota of 700 MT/month of Subsidized LPG Cylinders, 1,000 Tons of Non-Subsidized LPG and 500 Tons of Commercial LPG cylinders. The retail prices are in Table as follows:

Table -5.4.4: Retail prices of Petroleum Produts in 2018.

Petroleum Oil Products	Unit	Price
LPG		
Subsidised Cylinder	14.2 kg	589
Unsubsidised Cylinder	14.2 kg	882
Commercial Cylinder	19 Kg	1285
Petrol 95 Oct	Litre	49
HSD	Litre	46

(Source: DOT, Bhutan)

C) Demand projections for Petroleum

In 2017, about 19% of the country's primary energy was consumed by the Transport sector. The demand for petrol and diesel has grown by about 7 times between 2001 and 2018. In spite of stringent taxation on imported vehicles, the growth of sales of automobiles is about 9%. By 2019, the share of POL had grown to about 23% of country's energy consumption.

As per the SAARC Energy Outlook 2030 research, the anticipated long-term growth rate is likely to be 8.9 % for Petrol, 6.7% for Diesel and about 7.3 % for LPG. For other petroleum products, the expected growth shall be about 5% CAGR. These rates are less than the year-on-year growth witnessed in 2017 & 2018. The projected volumes till 2040 for Petrol, Diesel & LPG have been worked out based on these growth rates and are in Table 5.4.5 below:

Table -5.4.5: Growth of LPG, Petrol and Diesel in Bhutan

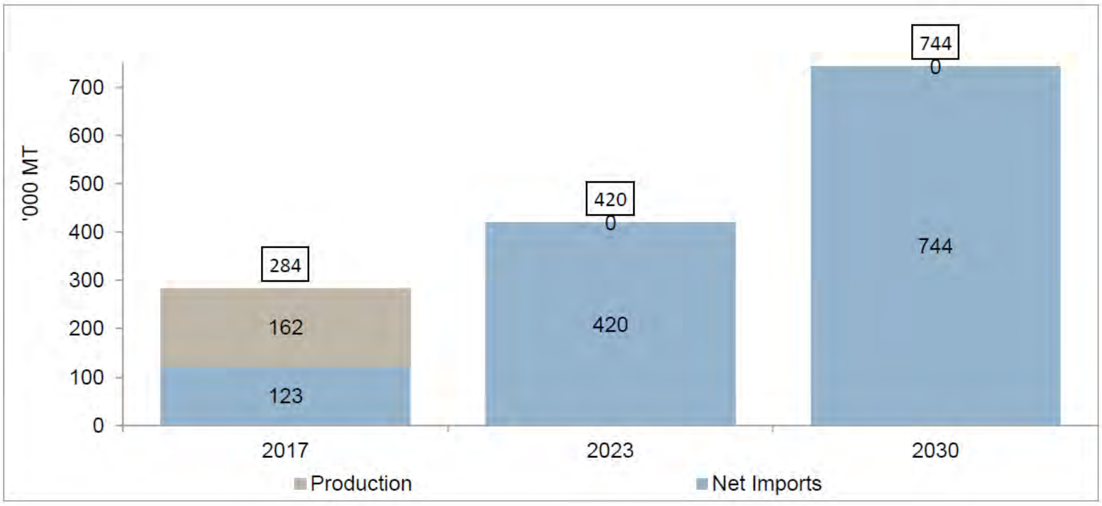
Demand Growth of Petrol & Diesel (in Mn MT), LPG (in Kt) in Bhutan							
Fuel	**Growth Rate**	**2017**	**2018**	**2025**	**2030**	**2035**	**2040**
Petrol	9% till 2030, 5% post 2030	0.02	0.04	0.07	0.11	0.14	0.18
Diesel	6.7% till 2030 and 4.5% thereafter	0.12	0.14	0.21	0.29	0.36	0.44
LPG	7.3% till 2025, 6% therafter	8	9.30	14.19	18.99	25.42	34.01

(SAARC Energy Outlook 2030 , Crisil Research)

5.4.3 Coal Sector

Bhutan is an exporter of Ferrosilicon alloys and Graphite. It requires coal to fuel its Ferro-alloys industry and Cement producing plants. The exports are likely to grow at about 6%. Besides, additional demand is also likely to emerge from new industries and as per the SAARC Energy Outlook 2030, the growth in coal demand is expected @ 7.6% CAGR. The annual demand for coal in 2017 was about 284,000 MT. The country has two operating mines, Habrang and Tshophangma operated by the State Mineral Corp of Bhutan. The coal production was about 80,253 MT in 2018. As no new mines are being planned, it is expected that after 2023, nearly the entire demand would be met from imports. The demand for coal is likely to grow to 420,000 MT by 2023 and to 744,000 MT by 2030.

Table-5.4.6: Growth of consumption of Coal in Bhutan



(SAARC Energy Outlook 2030 , Crisil Research)

Bhutan's requirement is for coking / semi-coking coal for its Ferro-Alloys industry. It is very small requirement of thermal coal.

5.5 Gas Supply options and feasibilities

Bhutan does not have any natural gas supplies or infrastructure to receive gas supplies. The demand for gas emerges only if its economic advantage over other sources is established and consumers are comfortable to switch over their prevailing fuel options in its favour. Once the economic advantage of gas is established, its demand can be worked out by estimating the extent of substitution or penetration in the basket of fuel that it can replace.

This study has attempted to explore the following:

- Options of gas supplies
- Estimate the landed costs for these options
- Compare the specific cost of thermal energy of gas with the existing various fuels to establish the extent of the economic advantage of gas over other fuels, if any.
- Explores the potential regions where gas it can penetrate and replace more expensive fuels.

5.5.1 Exploring supply options and estimating landed cost of gas

Bhutan is a land-locked country with no prospective gas fields / reserves. Gas supplies, if any, have to be imported from neighbouring countries. India and China are the two neighbours and the demand of both countries is well short of their production. Bangladesh and Nepal are separated by a 100-200 kms of India's mainland. Nepal has no reserves and Bangladesh's production is well short of its own demand. India, China and Bangladesh are importing LNG to sustain their demand. In India, many new LNG receiving terminals are coming up. Gas supply option from China is impractical as it involves a long distance and a harsh mountainous terrain as compared to India. India is developing a trunk pipeline just under 50 kms south of Bhutan's border, and is a natural choice for any prospective gas supplies.

Bhutan has 20 districts or Dzongkhags. Nearly 60% of Bhutan's population resides in the 7 main districts. Further, as per a Bhutan Update 2019 Report by the World Bank study, economic activities are concentrated in key towns and Dzongkhags. Nearly 60% of all firms registered in Bhutan are located in 6 of the 20 Dzongkhags and 25% of all firms are in Thimpu, the national capital of Bhutan. It is imperative that to begin with, Thimpu is a natural destination for any pipeline.

Three supply options have been considered, i.e.,

- **Option A:** A dedicated trunk pipeline connecting with nearby take-off point of India's Trunk Pipeline which has spare capacity on Contract Carrier basis. LNG shall be tied up with about 75-80% as Term LNG and the rest as Spot LNG.
- **Option B:** Multiple small diameter dedicated pipelines from the CGD network of the Geographic Areas (GA) in the adjoining districts with India. The spare capacity of India's pipeline would be tied up as per the regulations. LNG would be tied up in bulk and distributed as per the demand at various end-use locations.
- **Option C:** Small-scale /Virtual LNG Supply Chain using Trucks/Lorries with Cryogenic Containment system and Vaporiser stations at consumption points. This obviates the need for Options A & B.

The supply chain analysis and expected landed cost under these options is as follows:

A) Option A: A dedicated pipeline from India for RLNG and landed cost

The nearest pipeline connectivity for Thimpu, Bhutan can be from the Barauni – Guwahati pipeline which is in an advanced stage of construction by GAIL India Ltd. The take-off point could be Jalpaiguri which is about 250 kms away from Thimpu. Alternately, take-off can be from a proximate point in the New Jalpaiguri-Bongaigaon section near Pheuntsholing just inside Bhutan Border, or some other compressor station nearby. En route are some of the densely populated regions, which can also benefit.

LNG would be sourced from Dhamra (and possibly later from the proposed Kukrahati Terminal near Haldia), and transported by GAIL's trunk pipelines, the Dhamra-Angul-Bokaro-Jagdishpur pipeline and the Barauni – Guwahati pipeline. A firm tie up of about 70-80% of the pipeline capacity would be required to ensure adequate pipeline utilization and stability in pricing.

The supply chain and the cost elements are estmated as follows:

- The DES prices for term LNG supplies is assumed at Crude Parity of 12.5% in $/mmbtu,.
- LNG Terminal's Re-gasification charges are expected to be under 1 $/mmbtu. Regasification and other costs (port charges, Taxes & Duties) have been taken as 2 $/mmbtu.
- The Pipeline tariffs for the Indian pipelines from Dhamra are yet to be approved and notified by the PNGRB. They have been assumed as 1.5 $/mmbtu,.
- The cost of pipeline laying is derived from the contracts awarded by GAIL in 2016-17(@ INR 50-60 Millions/km for a 24-30 inch high pressure line) by discounting for Diameter and escalating at 5% per annum and for the difficult terrain. As per Pipeline industry thumbrule estimates, a pipeline of 12-inch at pressure of 95 Kg/cm2 can easily meet the requirement equivalent to 1500 – 2000 ktoe. Levelized pipeline tariffs are assumed with margin as 2.0 $/mmbtu.
- The distribution costs would include connecting spurs to nearby population along the route, and has been assumed as 10 $/mmbtu

- The landed cost have been worked out at Crude Prices at 40, 50 & 60 $/bbl.

The landed cost works out to 20.5 to 23 $/mmbtu for a 12-inch pipeline with 2 mmscmd flow as explained in Table below:

Table-5.5.1: Landed cost under Option A: 12-inch Dedicated Pipeline

Option A: Landed cost of LNG by dedicated Pipeline			
A). Crude Prices (in $/bbl)	40	50	60
B) DES at Crude Parity 12.5% (in $/mmbtu)	5	6.25	7.5
C) Liquefaction and Other	2	2	2
D) Pipeline Tpt Costs: India	1.5	1.5	1.5
E) Pipeline Tpt Costs: India – Bhutan	2	2	2
F) Bulk Consumer Costs (B+C+D)	10.5	11.75	13
G) Retail Distribution Costs	10	10	10
H) Retail Consumers Costs (F+G)	20.5	21.75	23

Notes
1.Term contract prices are negotiable and downward prices can be explored
2. Liquefaction, Pipeline and Distribution costs can be higher if consumption is low

(Source: Author as per Industry normse)

B) Option B: Multiple Links with CGD Network in bordering Indian districts and landed cost

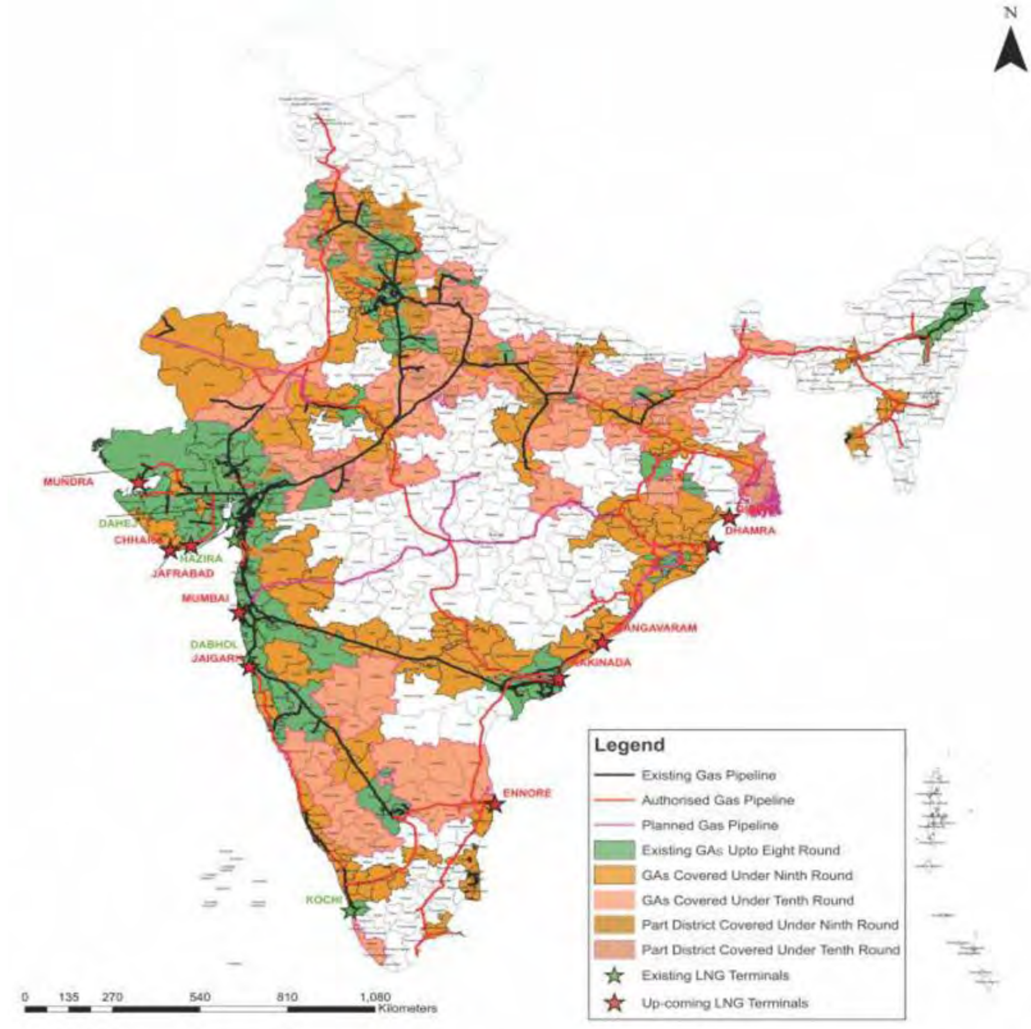
A number of districts of four Indian States, Arunachal Pradesh, Assam, West Bengal and Sikkim, are geographically abutting the South, West & East borders of Bhutan. The districts surrounding Bhutan can be seen in the figure below.

Fig-5.5.1: Map showing India's districts on the East, South and West of Bhutan

(Source: Election Commission)

GAIL's Barauni-Guwahati trunk pipeline would be passing through some of these districts. The PNGRB had identified several Geographical Areas (GA), comprising of one or more districts for a comprehensive development of CGD Networks as in PNGRB's map below.

Fig -5.5.2: PNGRB- Authorised Geographic areas for development of CGD Network in India



(Source: PNGRB)

The following GA / districts bordering Bhutan have been authorised by PNGRB in 2018 & 2019 (9th and 10th round of CGD Auctions) while a few adjoining districts have been included in the notifications for the 11th round, expected to be authorised in 2020:

9th & 10th Rounds of CGD: State-owned HPCL has emerged as the authorised entity for Darjeeling & Jalpaiguri Districts.

11th Round of CGD: PNGRB has proposed a Geographic Area comprising of Baksa, Barpeta, Bongaigaon, Chirang & Nalbari districts, for the forthcoming 11th bidding round, expected to be completed in 2020.

Bhutan has 20 districts or Dzongkhags. Nearly 60% of Bhutan's population resides in the 7 main districts. The geographic location is such that three pipelines can cover these 7 districts. These three links and the towns/ districts / population covered are displayed in the table below:

Table-5.5.2: Districts/Dzongkhags with high population, density and distance from key take-off points

City/Town	District	Population	Density (per sqkm)	Distances		
				Within Bhutan	From Jalpaiguri	From Bongaigaon
Pheuntsholing	Chukha	27,658	36.1	147 kms from Thimpu,	105	
Mebisa / Chhukha	Chukha	3,568	36.1	85 Kms from Pheuntsholing	191	
Chuzom Bridge	Thimpu			34 kms from Mebisa	225	
Paro	Paro	46,316	35.8	23 kms from Chhuzom Bridge,	248	
Thimpu	Thimpu	1,38,736	67.1	27 kms from Chuzzom Bridge	252	
Wangdue Phodrang	Wangdue Phodrang	42,186	9.8	69 kms from Thimpu	312	
Punakha	Punakha	28,740	25.9	15 kms from Wangdue Phodrang	327	
Samtse	Samtse	62,590	48	85 kms from Phentsholing	85	
Sarpang	Sarpang	46,004	23.6			66

(Source Author)

Instead of one trunk lines, this Option considers the following three small sized pipelines, which can be laid in shorter duration and provide access to gas supplies:

1. Jalpaiguri – Pheuntsholing – Mebisa – Chuzom Bridge – Thimpu – Wangdue Phodrang – Punakha – 327 kms A spur of 23 kms connects Paro from Chuzom Bridge.
2. Jalpaiguri – Samtse: 85 kms.
3. Bongaigaon to Sarpang: 66 kms.

The secondary network for Intra-Dzonkhags can be developed later. The landed cost under this option is based on following assumptions and the cost elements of the supply chain:

1. An upfront tie up of Term-LNG from the nearest LNG Terminal, i.e. Dhamra.
2. The DES prices have been assumed at Crude Parity of 12.5% in $/mmbtu. The cost have been worked out in three scenarios of prices of Crude, at 40, 50 & 60 $/bbl.
3. Regasification and other costs including Port Charges, Taxes & Duties, have been taken as 2 $/mmbtu
4. The Pipeline tariffs for the Indian pipelines from Dhamra are yet to be finalized. They have been assumed as 1.5 $/mmbtu upto the take-off points in respective CGD Networks.
5. A small dia pipeline of sub-12 inch size at medium to high pressures (45 - 95 Kg/cm2) can easily meet the requirement equivalent to 300 KTOE.
6. The cost of pipeline laying is derived from the contracts awarded by GAIL in 2016-17(@ INR 50-60 Millions/km for a 24-30 inch high pressure line) by discounting for Diameter and escalating at 5% per annum and for the difficult terrain.
7. Levelized pipeline tariffs assumed (with margin) as 0.5 $/mmbtu.
8. The distribution costs would include connecting spurs to nearby population along the route or from the capital cities of the province to nearby towns and highways.
9. The target segment are CNG Consumers, and PNG consumers from Industries, Commercial and Domestic consumers.

Table -5.5.3: Landed cost under Option B: Multiple connecting pipelines

Option B: Landed cost of LNG by Multiple links with India's CGD Network in adjoining GA			
A). Crude Prices (in $/bbl)	40	50	60
B) DES at Crude Parity 12.5% (in $/mmbtu)	5	6.25	7.5
C) L Regasification and Other (in $/mmbtu)	2	2	2
D) Pipeline Tpt Costs: India (in $/mmbtu)	1.5	1.5	1.5
E) Costs for short links with India's CGD Networks	2	2	2
F) Bulk Consumer Costs (B+C+D+E) (in $/mmbtu)	**10.5**	**11.75**	**13**
G) Retail Distribution Costs (in $/mmbtu)	10	10	10
H) Retail Consumers Costs (F+G) (in $/mmbtu)	**20.5**	**21.75**	**23**

Notes
1.Term contract prices are negotiable and downward prices can be explored
2. Liquefaction, Pipeline and Distribution costs can be higher if consumption is low

(Source Author as per Industry norms)

D) Option C: LNG Virtual Pipeline (Road Transportation) and landed cost

Over the past decade, the popularity of road transportation of LNG in trucks retrofitted and equipped with capability to handle cryogenic liquid container/tank has grown all over the globe Many cities in South India and other regions not connected by pipelines fulfil their demand by transporting LNG in this form. GAIL has recently commissioned the CGD for Bhubaneshwar by transporting LNG Container trucks all the way from Hazira, about 1,700 kms away.

The following assumptions have been made:

1. An upfront tie up of Term-LNG from the nearest LNG Terminal, i.e. Dhamra or Proposed Kukrahati Terminal near Haldia
2. The DES prices have been assumed at Crude Parity of 12.5% in $/mmbtu. The cost have been worked out at Crude Prices at 40, 50 & 60 $/bbl.
3. Other costs cover the Port Charges, Taxes etc,
4. Regasification is not required, and that cost is saved.
5. Road transportation for average about 1150 kms from Dhamra @ 2.5 to 3 $/mmbtu as per the prevailing industry thumb rule rates.
6. Retail distribution costs are taken as about 7.5 $/mmbtu and includes Vaporization costs.

The landed costs work out to be about 17.5 to 20 $/mmbtu benchmarked with Crude prices from 40 to 60 $/bbl as in the table below:

Table-5.5.4: Landed cost under Option C: Small-scale / Virtual LNG Supply Chain

Option C: Landed cost of Small-scale / Virtual LNG Supply Chain (by Road Transportation)			
A). Crude Prices (in $/bbl)	40	50	60
B) DES at Crude Parity 12.5% (in $/mmbtu)	5	6.25	7.5
C) Other costs (in $/mmbtu)	1	1	1
D) Road Transportation (in $/mmbtu)	3	3	3
E) Bulk Consumer Costs (B+C+D) (in $/mmbtu)	9	10.25	11.5
F) Retail Distribution Costs (in $/mmbtu)	7.5	7.5	7.5
G) Retail Consumers Costs (E+F) (in $/mmbtu)	16.5	17.75	19

Notes
1.Term contract prices are negotiable and downward prices can be explored
2.Transportation costs are for 1000 kms (Ex Dhamra), can come down Ex- Kukrahati / Haldia
3. Retail Distribution costs can be higher due to high cost of land and low consumer density

(Source:Author as per Industry normse)

5.5.2 Analysis of the options: Comparing Pipeline vs Virtual mode of supply

The 'RLNG Supplies by Pipeline' and 'Small-scale / Virtual LNG Pipeline' have their own merits and demerits.The comparison of the merits and de-merits of the supply chains has been done while evaluating this option in previous chapter at 4.

There are some merits in 'Virtual' mode. Initial costs are less. Operations can commence in just 2-3 years.This option is ideal for small volumes of say 10,000 kg/day for a receiving station.The scalability can be by installing additional storage or multiple stations at an appropriate demand centres, thereby pre-empting need for laying interconnecting pipelines. More Flexibility in mitigating risks like 'Take-or-Pay', by re-selling and transporting quantities elsewhere under contract for LNG tankers /lorries. But over a mid to long-term, escalations in road transportation costs are much more than the pipeline tariffs.To summarise,'Virtual' mode has some distinct benefits

- Initial capital costs are less.
- Operations can commence in 2-3 years, pipelines take 4-5 years or more to be laid
- This option is ideal for small volumes of say 10,000 kg/day for a receiving station. Benefit of choosing multiple locations in proximity with consumer base.
- The quantities can be can be scaled up later to the desired capacity.
- Flexibility in despatch schedules to supply destinations, hence, better utilization of the fleet.
- More Flexibility in mitigating risks like 'Take-or-Pay', by re-selling or diverting and transporting quantities elsewhere under contract for LNG tankers /lorries

The demerit of 'Virtual' mode is that road transportation costs escalate much more than escalation in RLNG pipeline tariffs.

5.5.3 Estimating potential gains on switching to gas

Prior to investing and switching to a new energy source, the policy makers compare the economic advantage in the long-run, volatility in prices, assured availability or energy security with the existing energy sources. Besides, the consent and conviction of the consumer is a key enabler for accelerating the switch over.

Bhutan is an electricity surplus nation. Its power sector is entirely on Hydropower save for some small capacity of DG sets.The author has analysed the cost economics of the of fossil fuels and compared it with the estimated cost economics of gas supplies as worked out in the 5.5.2 above.

The methodology adopted is:

- Determine the Specific cost of thermal energy in for the existing petroleum products
- Compare it with that of gas supplies
- Ascertain the potential gains for switching the existing energy options to gas,

A) Specific cost of Petroleum Products

The author has collected the prevailing retail prices for the various fuels, namely LPG (Subsidized, Non-subsidized & Commercial), Petrol and Diesel and their thermal energy to work out the specific costs in Nu / 1000 K Cals or in US $ / mmbtu. The specific costs are in the Table as follows:

Table-5.5.5: Affordability analysis: Comparing Landed cost under Options A, B & C with Petrol, Diesel & LPG

Comparision of cost of thermal energy in LPG, Petrol and Diesel in Bhutan						
Fuel	**Price**	**Unit**	**GCV**	**Unit**	**Price In INR/1000 Kcals**	**Price In USD/mmbtu**
14.2 kg LPG Subsidized	589	Nu/Cyl	11,900	Kcals/Kg	3.5	12.0
14.2 kg LPG -Non Subsidised	882	Nu/Cyl	11,900	Kcals/Kg	5.2	18.0
19 Kg LPG Comml	1285	Nu/Cyl	11,900	Kcals/Kg	5.7	19.6
Petrol	49	Rs/Litre	8269	K cals/litre	5.9	20.5
Diesel	46	Rs/litre	9185	Kcals/Litre	5.0	17.3

Notes
1. GCV of Petrol is 11,100 Kcals/Kg and density is 0.745 Kg/litre
4. GCV of LPG is 11,900 Kcals/kg
2. GCV of Diesel is 11,000 Kcals/Kg and density is 0.835 Kg/litre
5. Exchange rate is 1 USD = 73 INR
3. GCV of CNG is 10,000 Kcals/cu metres or 12,500 Kcals/kg
6. Conversion from Kcals to btu: 1 K cal = 3.966 btu

(Source: Author as per Industry norms)

B) Comparing Specific Cost of thermal energy in the existing fuels with the landed cost of gas in the Supply Options 'A', 'B' & 'C'

The prevailing pricing of the petroleum products and coal have been compared with the approx landed cost of Natural Gas by Pipeline (as in Options A & B) and Small-scale / Virtual LNG supplies (as in Option C). as collated in the comparision as brought out in the Table below:

Table-5.5.6: Comparision of specific cost of thermal energy in petroleum products and Natural Gas

Comparision of cost of thermal energy in Petroleum products and Natural Gas in Bhutan	
Fuel	**Price In USD/ mmbtu**
14.2 kg LPG Subsidized	12.0
14.2 kg LPG -Non Subsidised	18.0
19 Kg LPG Comml	19.6
Petrol	20.5
Diesel	17.3
Natural Gas in Option A: Regasified LNG by dedicated Pipeline	20 - 22.5
Natural Gas in Option B: Regasified LNG by multiple links with Indian CGD Networks	19 - 21.5
Natural Gas in Option C: Small-scale / Virtual LNG Supply Chain (By Road)	16.5 - 19

Notes
1. GCV of Petrol is 11,100 Kcals/Kg and density is 0.745 Kg/litre
2. GCV of Diesel is 11,000 Kcals/Kg and density is 0.835 Kg/litre
3. GCV of CNG is 10,000 Kcals/cu metres or 12,500 Kcals/kg
4. GCV of LPG is 11,900 Kcals/kg
5. Exchange rate is 1 USD = 73 Nu
6. Conversion from Kcals to btu: 1 K cal = 3.966 btu
7. Fuel prices as prevailing average retail prices in Bhutan

(Source: Author as per Industry normse)

It can be seen that cost saving in switching to gas is just about 10 – 20% for petrol, and practically negligible for diesel and LPG to Natural Gas.

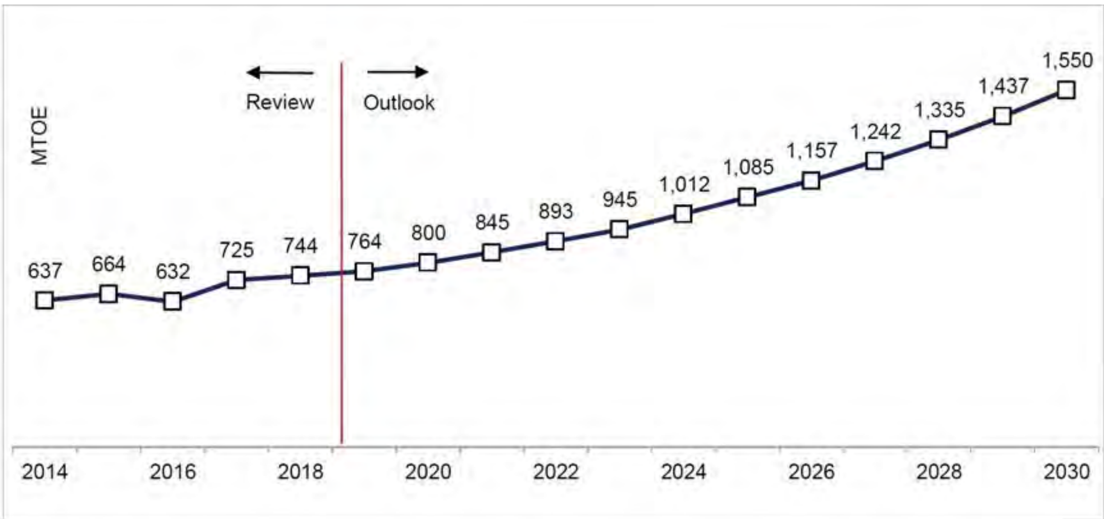
5.6 Gas demand estimation

5.6.1 Key economic drivers

A) Growth forecast of Primary Energy:

As per a SAARC / CRISIL research, the Primary energy requirement is likely to reach 1550 KTOE by 2030 (Refer Fig below). The key contributing sectors are Buildings, Industrial and Transport.

Fig -5.6.1: Growth of Primary Energy Cosumption in Bhutan



(Source SAARC Energy Outlook 2030, Crisil Research)

B) Environment protection & Climate Change

i) Impact of climate change

There has been a significant impact of the climate change the pattern of rainfall and melting of glaciers in the Himalayas. Bhutan's economy is exposed to revenues from the power exports to India. Besides, its national debt stood at about 100% of the GDP in 2019. The decline in the hydrology of its river systems on account of decline in the snow falls, rain falls and reduction in the size of its glaciers has impacted its power production by about 6% in 2017/18 & 2018/19. The sub-par generation and its impact on export earnings have been reflected in the Annual Report of BPC as also illustrated in a recent report, 'Bhutan Development Update, Recent trends in poverty and shared prosperity: Progress & Challenges' by the World Bank / IMF, as reproduced below:

Fig-5.6.2: Hydropower production profile and impact on revenue

(Source: Bhutan World Bank: Development Update ; Source MOF

ii) Initiatives of the Govt of Bhutan for Environment protection.

The Bhutan 2020 Vision document released in 1999, committed its resolve by enacting suitable policies and institutional framework for Environment protection and standards for air, water and environment health. Its National Forestry Master Plan (1996) commits it for ensuring a 60% forest cover in all times to come. It desperately needs to reduce firewood for household and shift to the eco-friendly LPG or piped gas.

In the COP-15, UNFCCC (2009), Bhutan committed to remain carbon neutral, wherein its GHG emissions, then estimated at 6.2 Million MT, would not exceed the carbon sequestration capacity of its forests. This commitment was reiterated in COP-21 at Paris (2015). The country's NDCs further pledges to promote efficiencies in demand side management. The Vision statement of its Economic Development Policy – 2016 reiterates its resolve to be a 'Green and self-reliant economy sustained by a knowledge based society guided by the philosophy of GNH'.

In Dec 2019, Bhutan released its National Energy Efficiency Policy. The objectives include reduction of fossil fuel consumption besides demand side efficiency plans for the key energy consuming sectors, Buildings (42%), Industry (37%) and Transportation (19%).

5.6.5 Sector-wise demand projections:

The projection of demand would depend upon the following factors:

- The growth in demand of fuels which gas could substitute
- The level of penetration during substitution

The candidate energy consuming segments have been analysed for the potential

A) Candidate segments with potential for gas demand

i) Power Sector: There is insignificant generation from HFO/Diesel/ Coal, and there are no plans to add any thermal power plant. Generation costs on hydro-power are much cheaper than gas. Besides, the country has a substantial capacity under construction. As such, there is little scope of any consumption of gas in this sector.

ii) Industries: The Industries would receive gas at Bulk prices, which shall provide a price arbitrage of about 20-25 % in energy costs.

iii) Buildings: The sector has a share of about 42% of the energy consumption. It is mostly in the form of heating and lighting requirement. The Economic Development Policy 2016 and the Tariff Policy, reiterate the commitment of the Bhutan Government to continue subsidized power to its LV consumers. With the capacity addition of Hydro-power, it seems unlikely that the country would need gas for this sector.

iv) Transportation: As per the National Energy Efficiency & Conservation Policy – 2019, the transport sector consumed about 19% of the Primary Energy in 2014. The increase in incomes has led to growth in automobiles. As per the SAARC Energy Outlook – 2030, POL comprised of 23% of the energy consumed in 2017. This sector is witnessing a healthy growth of over 7%. While comparing the specific cost of thermal energy of different fossil fuels, the expected landed price of gas is just about 10 – 15% lower than that of petrol and similar to diesel.

iv) Coal consumption by Industries: Bhutan imports coking and semi-coking coal, mostly for its metallurgical properties in its ferro-alloys industry and gas cannot substitute the same.

v) Household: As seen in the table 5.6.1., there is no cost advantage on gas over LPG. However, the country receives only 7,000 MT / annum of subsidized LPG against its consumption of over 8,000 MT. As the consumption of LPG grows, the consumption of commercial / Non-subsidized LPG is likely to increase. As per its Constitution and the National Council Act, the government can be advised to review its policies so that the nation is able to fulfil the aspirations of its people. Suppling piped gas in the towns would free up the subsidized LPG, which can be supplied to the Rural areas, where the incomes are quite low. Besides, the government would be motivated to substitute firewood and meet its climate change commitments for maintaining forest cover and their bio-diversity to promote piped gas to city/ town dwellers and supply LPG cylinders to rural areas with low income. Besides, consumers prefer the convenience and safety of piped supply.

B) Estimating the level of Penetration / Substitution

While comparing the Specific cost of thermal energy of different fuels for the petroleum and LPG sector, gas is only marginally economical for substituting Petrol, and similar for Diesel & the Commercial / Non-subsidized LPG. The substitution of the Liquid fuels by gas can only be considered on the basis of the fact that gas is a cleaner fuel with lower environmental impact. Substitution of LPG can also be considered for the convenience/ ease in handling by domestic and commercial consumers and for helping the state in higher allocation of subsidized LPG for the rural population, which are economically weaker.

The expected demand projections for various petroleum products are exhibited in the Table ….At Para 5.5.2 above. The level of substitution for different fuels by gas will depend upon the arbitrage, availability, consumer behaviour and Government policy initiatives. The following assumptions have been made for working out likely substitution quantities:

- **Petrol:** Growth predictions from Exxonmobil are that the penetration of CNG-vehicles shall be around 4.5% p.a. In India, CNG is gaining popularity and some ripple effect of consumer behaviour is expected to permeate across the border. However, in absence of a significant price arbitrage, which is less than 20%, the demand shall pick up only after ascertaining the future pricing.
- **Diesel:** Industries comprise of about 11% of the total consumption. The Industries would receive gas at Bulk prices, which shall provide a price arbitrage of about 20-25 % in energy costs. Industries provide sizeable volumes and returns for the CGD operators. They are likely to gain access on priority. Besides, Diesel has higher environmental impact compared to gas. The substitution considered is 5% in 2025, 10% in 2030 and 15% thereafter.
- **LPG:** However, penetration is constrained by the difficulties in providing access to all household consumers. Accordingly, switch has been assumed as about 10% in FY 2025, 15% in FY 2030, 25% by 2035 and 30% by 2040 have been considered.

The penetration of gas against different fuels as discussed above emerges as in the Table below.

Table -5.6.1: Summarizing Penetration level of gas by switching of fuels

Summarizing level of penetration of gas by switching of fuels					
Fuel	**Cost Benefit in %**	**Level of Penetration**			
		2025	**2030**	**2035**	**2040**
Petrol	5 – 20%	0%	0%	0%	0%
Diesel	Nil	5%	10%	15%	15%
LPG	Nil	10%	15%	20%	25%

(Author's assumptions)

5.6.3 Demand Summation

Based on the above analysis, Transportation sector and the households consuming LPG have been selected as the candidate segments. The level of penetration of gas over the period of time under consideration has also been discussed as above.

With the above assumptions, the likely substitution of Diesel and LPG by LNG emerges between 0.009m in 2025 to about 0.059 MTPA in 2040.

Table -5.6.2: Demand for LNG by Fuel Switch in Bhutan

Fuel	Growth Rate	2017	2018	2025		2030		2035		2040	
				Expected Demand	Switch Over	Expected Demand	Switch Over	Expected Demand	Switch Over	Expected Demand	Switch Over
Petrol	9% till 2030, 5% post 2030	0.02	0.04	0.07	0.00	0.11	0.00	0.14	0.00	0.18	0.00
Diesel	6.7% till 2030 and 4.5% thereafter	0.12	0.14	0.21	0.01	0.29	0.02	0.36	0.05	0.44	0.06
LPG	7.3% till 2025, 6% thereafter	8	9.30	14.19	1.35	18.99	2.71	25.42	4.83	34.01	8.08
LNG Demand					0.009		0.025		0.046		0.059

The demand for Petrol and Diesel is in Million MT, for LPG in Kilo MT

Notes
1 Petrol switch over to LNG: Nil
2. Diesel switch over to LNG: 5% IN 2025, 10%-2030 and 15% thereafter
3 LPG switch over to LNG: 10% IN 2025, 15%-2030, 20% IN 2035 and 25% thereafter
4. Conversion of equivalent quantities of Liquid Fuels to LNG on thermal energy basis as per industry norms.

(Source: Author's assumptions)

5.6.4 Analysis of gas demand, supply options

Gas demand and the suitable supply option: The 2 mmscmd pipeline flow considered above can fulfil energy requirement of about 600 KTOE, which is nearly three/fourths of the entire Primary Energy requirement of Bhutan. Besides, Petrol constitutes about 25% of the total petroleum products or about 5% of the Primary Energy consumption or just about 40 KTOE. The gas required to substitute even a quarter of the petrol consumption would be in the range of about 35,000 KT/annum of LNG, or about 125,000 cm, or 1/16th of the design flow for the pipeline.

The emerging gas demand as in Table 5.6.2 Above translates to volumes in the range of about 30 to 35 thousand cubic metres per day in 2025 to about 210 to 220 thousand cubic metres day in 2040, well short of a volume of about 2 mmscmd for a 12-inch trunk pipeline under Option A. The 12-inch pipeline is just not required. Laying a pipeline of 6-inch or 8 inch may lead to higher tariff by several times. This would result in a hike of landed price and make gas uneconomical for switching. The options A & B (trunk and feeder pipelines options) are therefore uneconomical and not feasible till a bulk consuming plant like a fertilizer or a petrochemical is planned.

Option 'C', i.e., 'Small-scale / Virtual LNG' Supply Chain with Storage Tanks and Vaporizers of appropriate capacity, can operate for smaller volumes and therefore appears to be the best way forward. The advantage is that capacity for the Receiving, Storage and Vaporizors of LNG matching with the demand as low as 5,000 to 10,000 cubic metres per day can be installed at the key demand centres like Thimpu, Pheuntsholing, Chukha, Mebisa, Paro, Punakha, Sarpang and Samtse. CNG stations can be developed readily in 2 to 3 years at these key cities/towns. PNG network can also be developed subsequently.

5.6.5 Growth of Gas: Key challenges and enablers

Some of the key challenges are as follows:

Electric Vehicles: Under Sustainable Low-emission Urban Transport Systems Project, the Government of Bhutan has launched a plan in 2018 to electrify 500 taxis (of its fleet of total 535 taxis) in a course of three years. The programme extends beyond taxis and includes designing and implementing an innovative financial mechanism to support the introduction of electric vehicles alongwith supporting charging infrastructure in six main dzongkhags (districts) and the city of Pheuntsholing, located just inside Bhutan from the Indian border. EVs are more efficient than Internal Combustion engines, and with surplus power, Bhutan stands to gain in its efforts to reduce fossil fuel consumption in Transportation sector. The easy accessibility to electricity, low tariffs and surplus power availability are the motivating enabler for the growth of Electric Vehicles. But, the higher cost is the key road block.

Abundant Hydro-Power: Bhutan is a power surplus country. More hydropower capacity additions are under implementation / construction. Generation costs on hydro-power are much cheaper than gas. The country's tariff policy favours subsidized cost for LV consumers (Ref: above). The households are more inclined to prefer electricity for cooking and heating.

The key enablers for growth of gas would be the government policies and support. Key enablers are

Taxes: Providing a low tax structure would help to keep the gas prices beneficial for the consumers. India, the neighbouring country has a lower tax structure for Natural gas as compared to Petrol & Diesel, and is planning to further reduce the taxes.

Revising emission standards: The release of GHG gases and pollutants by Diesel and Firewood/ Biological fuels are contributors in Climate Change / Global Warming. The pollutants also pose greater health hazards for citizens. Climate change can lead to decline in glaciers and the rainfall, thereby adversely affecting its growth of hydropower. Gas has lower carbon footprints and is less hazardous. Stringent measures and control on emissions by reducing Petrol, Diesel & Firewood in preference to gas could pay rich dividends for economic growth and health of citizens.

Switch-over from Bio-mass to LPG / Gas: This share of Bio-mass is about 38% of Bhutan's Primary Energy consumption. This segment would need to shift to other sources to ensure the NDC of Carbon footprints and also ensuring forest cover of 60%. For the consumers, the alternate source to switch over can be electricity or LPG.

5.7 Summary of Key Drivers for growth of Bhutan's Gas Sector

A) Limited Potential

Primary energy consumption itself is just 744 KTOE in 2018 and is expected to reach 1 MTOE in 2024 and grow to about 1.55 MTOE in 2030. The country has utilized hydropower potential to its advantage. It is surplus and a net exporter (about 65% of its generation). About 2,780 MW of Hydropower plants are under implementation. Bhutan does not need any gas for power generation.

Petroleum and Coal sectors have limited consumption and demand is limited to less than 0.3 MTOE in 2017 and would reach just about 1.3 MTOE by 2040.

Table-5.7.1: Projected Growth of Fuels

PROJECTED GROWTH OF FUELS (In KTOE)			
FUEL	FY 2017	FY 2030	FY 2040
Petroleum Products	165	398	654
LPG	8	20	35
Note:Petrol, Diesel and LPG constitutes 90% of Petroleum Products.			

(Source: SAARC Energy Outlook 2030, CRISIL,)

As such, the volumes of penetration of gas are limited to just about 10,000 Tons/year in 2025 to about 60,000 Tons/year in 2040.

B) Opportunity

The pricing of petroleum products do provide the cost-saving opportunity for Petrol and Diesel consumers to switch to gas. The bordering regions with India are densely populated and can benefit with connectivity with India's City Gas Distribution (CGD) network. However, the volumes are so less that pipelines may not be economical.

C) Options

The Small-scale / Virtual LNG Supply chain under Option 'C' i.e., LNG supplies by road trucks equipped with cryogenic cargo containment and LNG Storage and Vaporizers at multiple points of end use, is the best option. It provides quick access, low investment, lower risks, potential of penetrating the far flung areas at competitive prices. Bhutan's cities are within 1,050 to 1300 kms of Dhamra LNG terminal, and this supply chain option can be explored for direct supplies to its cities.

D) Policy Initiatives for environment protection and poverty alleviation

The country's generation is largely dependent on Hydropower. However, as experienced in 2018 & 2019, Climate change can seriously impact the hydrology of the rivers and consequences can affect power generation (Refer 5.6.1 B above) Minimising GHG emissions is a priority to address Climate Change. Gas is a less polluting fuel as compared to refined Petroleum products and a clean alternative to Firewood.

In its Economic Development policy 2016, Bhutan's strategies are minimizing the ecological footprints and promote the nation as an 'organic' brand. Gas as a clean fuel offers environmental benefits and can help in mitigating GHG emissions. It merits the government support and suitable policy interventions for a cleaner Bhutan.

Chapter 6: BBINS Intra Regional Trade

6.1 Overview

Cooperation for intra-regional trade of natural gas would be driven by the following key drivers:

- Affordability for consumers
- Long-term demand for energy
- Opportunities for investors in production, pipelines, RLNG terminals
- Political facilitation for availing benefits in energy accessibility and economic growth

The previous chapters of the report have dealt with country-wise analysis of the gas environment and the demand. The demand for gas as a 'preferred' fuel has emerged due to it being a clean fuel and/or it being an economical option. Its medium and long term demand has been well established for India, Bangladesh, Sri Lanka, Nepal and Bhutan. The BBINS region is likely to witness 6-8% growth in GDP in the short to mid-term. India alone is expected to contribute one third of the growth in global energy consumption. However, the BBINS region is short of indigenous/domestic gas reserves and supplies. It is a net importer of gas in the form of LNG. As discussed in Para 7.4 (Part 1), a large share of the global demand for LNG is likely to emerge from India, Bangladesh and Pakistan. The LNG producing markets have grown significantly and are on the lookout for new consumers. The beginning of trade within the BBINS Region provides an opportunity for strategic partnership for collective sourcing LNG at economical prices from the international markets.

6.2 Key drivers for trade

As discussed earlier, the key drivers for intra-regional trade are:

1. The expansion of India's pipeline network close to the neighbouring nations, the growth of LNG receiving terminals in India and likely surpluses in availability of gas and pipeline capacity ,
2. The high dependence on gas for Bangladesh surmounted by depletion of its existing land based gas-fields, skewed pipeline hydraulics due to its upcoming LNG import terminals and off-shore gas exploration in deep south,
3. Sri Lanka, which does not consume any gas, has resolved to include gas in its energy basket. It plans to draw a time-bound program for a planned introduction of gas. It also plans to install an LNG trading terminal at Hambantota, a deep water port, which augers well for opportunities of cooperation with neighbouring terminals in India and Bangladesh with the objective of optimizing LNG sourcing and operational efficiencies,
4. The dependence of Bhutan and Nepal on India for their petroleum products, population density and demand in four provinces of Nepal and the Bhutan valley bordering India and 'virtual' LNG supplies offering opportunity for economic benefit for consumers to switch from petrol and diesel to gas.

This appears to be the ideal time to commence pursuit of intra-regional cooperation.

6.3 Intra-regional gas connectivity and trade between India and Bangladesh

a) The economics of supplies from India: As discussed in the Ch.2 , based on the latest pricing of its CNG, Petrol and Diesel in Bangladesh, the cost of thermal energy in these fuels was calculated. It was seen that Petrol costs about 33 $/mmbtu and Diesel costs about 22 $/mmbtu. Piped gas would be available at less than 20 $/mmbtu including all marketing and distribution margins. As compared to the same, prices ex-India borders for Long-Term (DES prices were assumed at Crude parity of 12.6% plus 50 cents, Regasification at 1 $/mmbtu, Tptn at 1 $/mmbtu and all taxes and marketing margins as per prevailing rates) for Crude between 40 to 50 $/bbl, could be in the range of 9 to 10.5 $/mmbtu. For crude at 60$/bbl, the ex-India prices could be higher at around 12 – 13$/mmbtu.

b) Options & Development of Infrastructure: The Ministry of Petroleum and Natural Gas, Government of India has identified connectivity with Bangladesh at Satkhira border point near Khulna, as an initial outreach to Bangladesh for cross-border trade. Many prospective Indian suppliers have evinced interest. In July 2019, the PNGRB granted a 24-inch pipeline from Kanai Chatta to Shrirampur near the Satkhira border to H-Energy. As per PNGRB authorization, the completion date is July 2022. This pipeline can carry gas from Dhamra terminal of Adani Gas or the proposed FSRU based terminal of H-Energy (at Kukrahati near Haldia) to Bangladesh.

c) Implementation of Indo- Bangladesh trade: It is gathered that Bangladesh is in the process of having a bilateral agreement with India?. The implementation of trade therefore, requires bilateral discussions at the Government-to-Government level or with other state-owned or private players. Bilateral trade can begin only with a binding contract on pricing, with some firm quantities, which shall become the basis for the Investment Decision or Financial Closure by the concerned stake holders.

d) Creation of a Gas Exchange and Hub: As discussed in Ch 1, Indian Gas Exchange has commenced gas trade using three important gas 'hubs', namely Dahej, Hazira and Onuru. Dahej and Hazira have LNG storage facilities and a robust network of pipelines owned by GAIL, GSPL and RGTIL and some spur lines feeding large consumers like Fertilizers, Steel or Power plants. With the pipeline connectivity, Bangladesh can seek access to India's gas hubs / exchange. In due course of time, the Indo-Bangla gas 'transfer point' has the potential to develop as a bilateral hub between consumers and suppliers of two countries, and can be mapped on the exchange for facilitating trade opportunities.

6.4 Sri Lanka:

As mentioned earlier, Sri Lanka has plans to install an LNG terminal along with a gas-fired power plant at Kerawalapitiya, near Colombo. Besides, Sri Lanka has entered into an agreement with a private entity to launch a floating storage and LNG trading hub at the Hambantota port. The trading hub would be eyeing OGVs(Ocean Going Vessels) with LNG bunkering as well as the LNG receiving terminals in the nearby region. The intra-regional cooperation with the terminals of India and Bangladesh can be two fold:

- For economic sourcing of LNG with suppliers
- For optimizing utilization and operational efficiencies by exchanging cargoes with partnering terminals in the region

6.5 Nepal:

As discussed earlier, the landed cost of gas from India by 'virtual' LNG mode provides economical thermal energy about 40% cheaper than petrol and about 15-20% cheaper than diesel (refer tables 4.5.5 & 4.5.8). Besides, as per the demographic analysis, the four provinces with highest population density (Province-2, Baghmati Pradesh, Province-5 and Province 1) are in close proximity with India's geographical areas which have been awarded to entities to develop City Gas Distribution (refer Table 4.5.2 & 4.5.3). As such, Nepal stands to gain with introduction of gas in its energy basket. The intra-regional cooperation shall be in two stages:

- To begin with, 'virtual' LNG supplies can be introduced in the four provinces, as mentioned above
- This can be followed by interconnectivity through small diameter pipelines from the trunk lines feeding the CGD networks in the neighbouring areas across Indian border.

6.6 Bhutan:

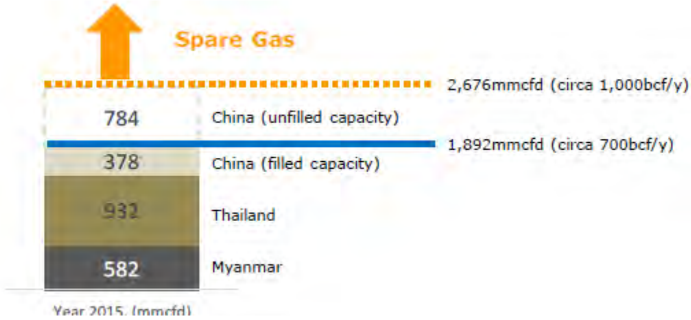
As in the case of Nepal, Bhutan too can gain by introducing gas in its energy basket. It has been analysed in Chapter 5 that 'virtual' LNG supplies from India offer economic benefits to it bulk-diesel consumers and also in substituting petrol. It can also fulfill the shortages in LPG demand (refer Tables 5.5.4 & 5.5.5). The introduction of gas can be in two stages:

- 'Virtual' LNG supplies can commence in the more populous Dzongkhags (as analysed at Table 5.5.2).
- This can be followed by interconnectivity by small diameter pipelines from India's gas pipeline grid, as explained above in the case of Nepal.

6.7 Expanding regional boundaries: Connectivity with Myanmar

Myanmar has discovered significant quantities of gas from 2002 onwards. Its proven reserves have more than quadrupled and are more than 40 tcf, almost as much as India. It consumes only about a fourth of its consumption and exports the remaining gas to Thailand and China. China has a dual crude and gas pipelines from Myanmar and about 25-30% of the gas exports move to China and the remaining to Thailand. The following figure gives a picture of the likely scenario, as and when production further picks up from Myanmar:

Fig:6.7.1 The Scenario for Potential Exports from Myanmar



(Source: BP Statistical & Remboll)

As per a Ramboll report cited in the GSMP -2018, surplus Piped Natural gas from Myanmar may be available at about 4-5 $/mmbtu. However, it is gathered that the gas production has not increased as per the production plan. Besides, Thailand is pressing Myanmar for increase in its quantities. In such a scenario, pipeline connectivity with Bangladesh and India would depend on the surpluses or willingness of China to forego some quantities.

As Myanmar shares its geographical boundaries with India and Bangladesh in North-East, a pipeline connectivity would overcome the imbalances as well as trigger the establishment of a Regional Grid in South Asia.

6.8 Expected Benefits in Intra-Regional trade in gas in the BBINS

The potential fiscal benefits for the intra-regional trade in BBINS have been estimated on the basis of the likely trade volumes as enumerated in the respective country reports for Bangladesh, Nepal and Bhutan (in the Chapters 2, 4 & 5 of Part 2 of this report) for the importing and exporting countries. The trade benefits can be in excess of 1.2 Bn $/annum in 2025 and can go upto 19 Bn USD/ annum in 2030, and about 3.6 Bn USD / annum by 2040, as enumerated in the table below :

Table 6.8.1 : Expected Benefits in Intra-Regional trade in gas in the BBINS region (in Million $ / annum)

Country	2025			2030			2040		
	Trade	Importing nations @ 5$/mmbtu	Exporting nation @ 2 $ mmbtu	Trade	Importing nations @ 5$/mmbtu	Exporting nation @ 2 $ mmbtu	Trade	Importing nations @ 5$/mmbtu	Exporting nation @ 2 $ mmbtu
	MMTPA	Mn $/year	Mn $/year	MMTPA	Mn $/year	Mn $/year	MMTPA	Mn $/year	Mn $/year
BANGLADESH	3.0	750	300	4.0	1000	400	7.5	1875	750
NEPAL	0.5	125	50	1.3	325	130	2.7	675	270
BHUTAN	0.01	2	1	0.03	6	3	0.06	15	6
TOTAL	**3.5**	**877**	**351**	**5.3**	**1331**	**533**	**10.3**	**2565**	**1026**

Note:
1. Expected benefit for 1 Ton of LNG @ 1$/mmbtu is about 50 $
2. Expected trade volumes as estimated in the respective Country's Analysis in Chapters 2, 4 & 5.

Annexures

Photo Credit: IGU : 2020 World LNG Report

Annexure - I

New Exploration Licensing Policy (NELP)

New Exploration Licensing Policy (NELP) was formulated by the Government of India, during 1997-98 to provide a level playing field to both Public and Private sector companies in exploration and production of hydrocarbons with Directorate General of Hydrocarbons (DGH) as a nodal agency for its implementation. To attract more investment in oil exploration and production, NELP has steered steadily towards a healthy spirit of competition between National Oil Companies and private companies. This has been a landmark event in the growth of the upstream oil sector in India. The foreign and Indian private companies are invited to supplement the efforts of National Oil Companies in the discovery of hydrocarbons. The development of E&P sector has been significantly boosted through this policy of Government of India, which brought major liberalization in the sector and opened up E&P for private and foreign investment, where 100% Foreign Direct Investment (FDI) is allowed. Under NELP, acreages are offered to the participating companies through the process of open competitive bidding. DGH held nine rounds of bidding as under:

Chronology of NELP Events:

Round	Launch Year	Signing Year
PRE-NELP Exploration	1980	1980-1995
PRE-NELP Field	1992	1992-1993
NELP-I	1999	2000
NELP-II	2000	2001
NELP-III	2002	2003
NELP-IV	2003	2004
NELP-V	2005	2005
NELP-VI	2006	2007
NELP-VII	2007	2008
NELP-VIII	2009	2010
NELP-IX	2010	2012

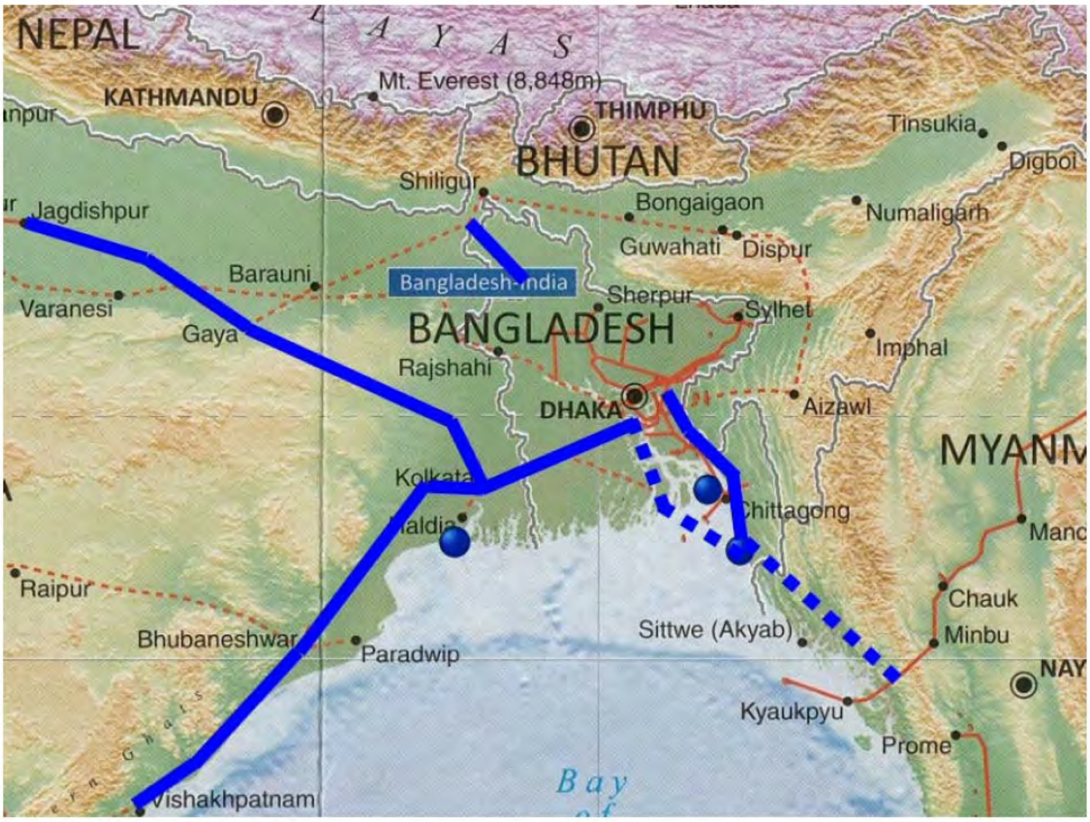
(Source: DGH Website)

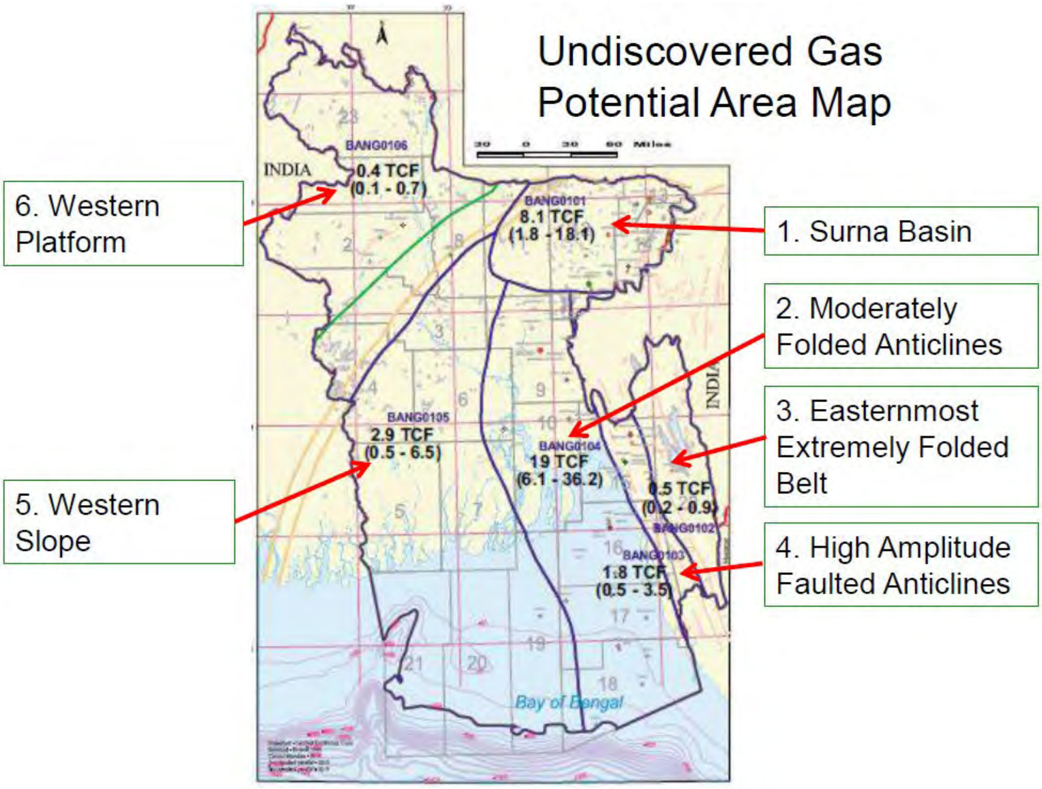
Blocks Awarded Under NELP Rounds:

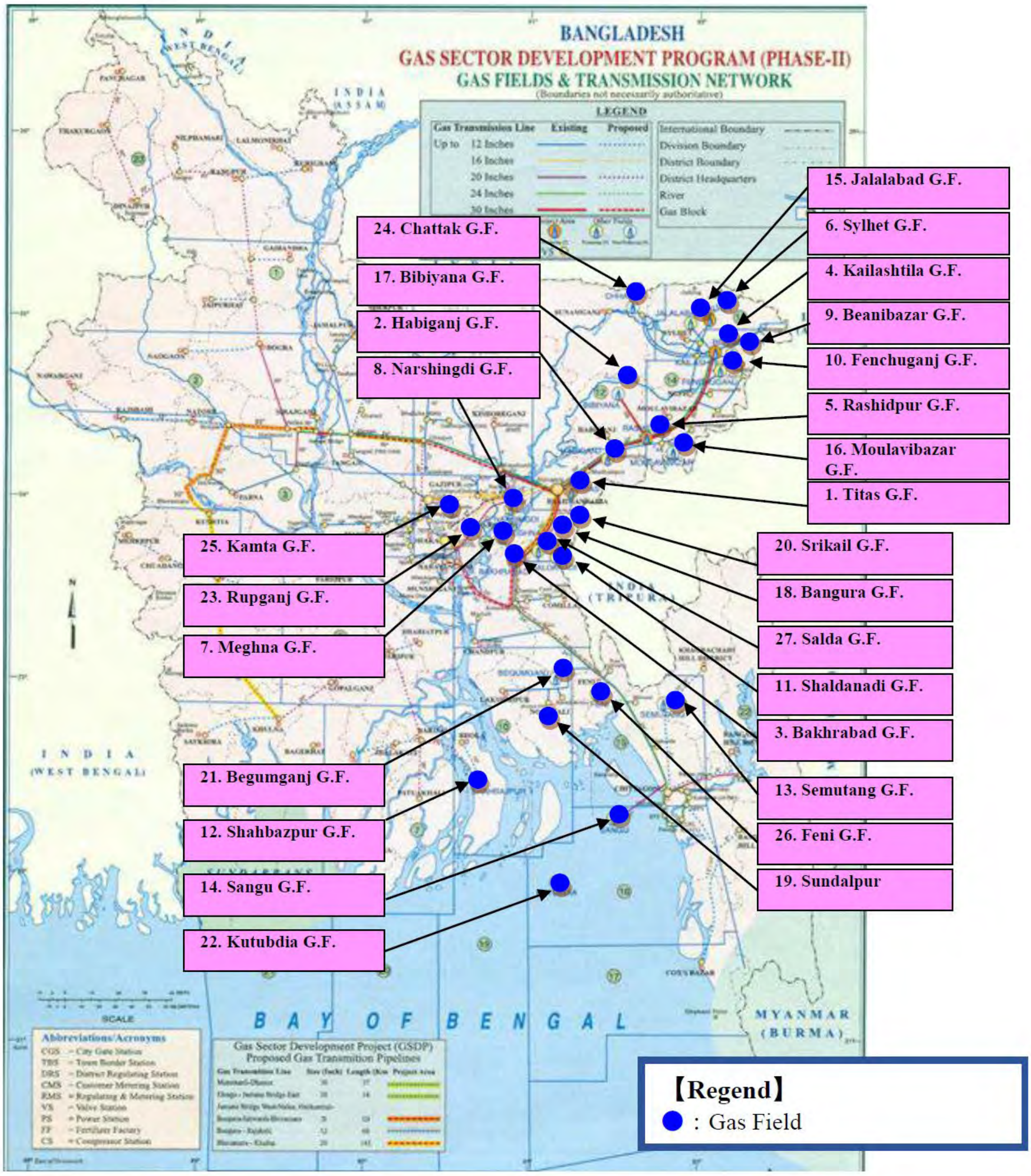
Round	Awarded			
	Deep-water	Shallow Water	Onland	Total
NELP-I	7	16	1	24
NELP-II	8	8	7	23
NELP-III	9	6	8	23
NELP-IV	10	0	10	20
NELP-V	6	2	12	20
NELP-VI	21	6	25	52
NELP-VII	11	7	23	41
NELP-VIII	8	11	13	32
NELP-IX	1	3	15	19
Total	**81**	**59**	**114**	**254**

(Source: DGH Website)

Several Oil & Gas discoveries have been made under these NELP awarded blocks.


NEPAL
KATHMANDU
Mt. Everest (8,848m)
THIMPHU
BHUTAN
Tinsukia
Digboi
Shiliguri
Bongaigaon
Numaligarh
Guwahati
Dispur
Jagdishpur
Barauni
Bangladesh-India
Sherpur
Sylhet
Varanesi
Gaya
BANGLADESH
Imphal
Rajshahi
DHAKA
Aizawl
Kolkata
Chittagong
Haldia
Raipur
Chauk
Minbu
Bhubaneshwar
Paradwip
Sittwe (Akyab)
Kyaukpyu
Prome
Vishakhpatnam
Bay


Undiscovered Gas Potential Area Map
6. Western Platform
BANG0106
0.4 TCF
(0.1 - 0.7)
INDIA
BANG0101
8.1 TCF
(1.8 - 18.1)
1. Surna Basin
2. Moderately Folded Anticlines
BANG0105
2.9 TCF
(0.5 - 6.5)
BANG0104
19 TCF
(6.1 - 36.2)
3. Easternmost Extremely Folded Belt
0.5 TCF
(0.2 - 0.9)
BANG0102
5. Western Slope
BANG0103
1.8 TCF
(0.5 - 3.5)
4. High Amplitude Faulted Anticlines
Bay of Bengal


BANGLADESH
GAS SECTOR DEVELOPMENT PROGRAM (PHASE-II)
GAS FIELDS & TRANSMISSION NETWORK
24. Chattak G.F.
17. Bibiyana G.F.
2. Habiganj G.F.
8. Narshingdi G.F.
15. Jalalabad G.F.
6. Sylhet G.F.
4. Kailashtila G.F.
9. Beanibazar G.F.
10. Fenchuganj G.F.
5. Rashidpur G.F.
16. Moulavibazar G.F.
1. Titas G.F.
25. Kamta G.F.
23. Rupganj G.F.
7. Meghna G.F.
20. Srikail G.F.
18. Bangura G.F.
27. Salda G.F.
11. Shaldanadi G.F.
3. Bakhrabad G.F.
21. Begumganj G.F.
12. Shahbazpur G.F.
14. Sangu G.F.
22. Kutubdia G.F.
13. Semutang G.F.
26. Feni G.F.
19. Sundalpur
BAY OF BENGAL
MYANMAR (BURMA)
INDIA (WEST BENGAL)
【Regend】
● : Gas Field

List of Hydropower Projects >50 MWs with anticipated Date of Power Generation

Hydro power plant	Installed capacity (MW)	Power generation from
Likhu-1, Likhu -2 , Likhu A	109	FY22
Lower Solu	82	FY21
Upper tamakoshi	456	FY21
Middle Bhotekoshi	102	FY21
Likhu-IV	52	FY22
Rasuwagadhi	111	FY21
Solu Khola (Dudhkoshi)	86	FY22
Trishuli 3A	60	FY21
Upper Lapche	52	FY23
Middle Tamor	52	FY22
Trishuli Galchi	75	FY23
Sanjen Khola	78	FY24
Arun -3	900	FY26
Upper Karnali	900	FY27
Tanahu Hydro Ltd	140	FY23
Total	3,256	

Part 2 (B): Analytical Study to assess the potential of gas for Regional Energy Cooperation in BBINS

Annexure II

Role and Key Regulations of PNGRB, the Downstream Regulator

PNGRB Act 2006 provides for the establishment of an independent regulatory board (PNGRB) as a downstream regulator to regulate the activities of companies related to:

- Refining
- Processing
- Storage
- Transportation
- Distribution
- Marketing and Sale of petroleum, petroleum products and natural gas and City Gas Distribution (CGD)

The various functions of PNGRB are as under:

1. Protect interests of consumers by fostering fair trade & competition amongst entities
2. Register entities for
    - Market notified petroleum, petroleum products and natural gas, subject to the contractual obligations of the Central Government,
    - Establish and operate LNG terminals
3. Authorize entities for:
    - Lay, build, operate or expand a common carrier
    - Lay, build, operate of expand city/local natural gas distribution Network
    - Declare pipelines as common carrier or contract carrier
4. Fix Transportation Rate for Common & Contract carriers
5. Define Pipeline Access Code
6. Define Safety standards
7. Define Affiliate Code of Conduct (for 'Arms-length relationship')

Important Regulations notified by PNGRB on Natural gas pipelines (NG P/Ls)

The various important regulations notified by PNGRB on natural gas pipelines so far are as under:

1. Authorization of Entities for laying/ building/ operating or expanding Natural Gas Pipelines

    For Existing / Under-Operation NG P/Ls before the Appointed Day:
    NG P/Ls authorized by Central Govt. prior to Appointed Day do not require any authorization from Board. However, NG P/Ls not authorized by Central Govt. prior to Appointed Day shall submit applications in prescribed format for grant of authorization by PNGRB through a public-consultation process.

    For Fresh NG P/Ls after the Appointed Day:
    After the Appointed Day, no NG P/L will be laid, built, operated or expanded without PNGRB's authorization. Proposals for new NG P/L can originate from any interested entity through an Expression of Interest (EoI) or suo-moto from PNGRB also. Authorization is granted on basis of competitive. The above regulation of PNGRB mainly defines procedure for authorization for laying, building, operating or expanding of new pipelines on Common Carrier/ contract Carrier basis. Regulations have specified certain minimum eligibility criteria (covering both technical and financial capabilities) for entities to participate in the bidding process and PNGRB shall entertain only those EOIs that fulfill the minimum eligibility criteria. Dedicated pipelines don't come under purview of this Regulation.

2. **Network Access Code**
   The main objective of this regulation is to ensure Gas supply to any place from any place for any one at competitive cost on non-discriminatory basis. This regulation defines terms of access amongst various pipeline systems of different entities at interconnecting points. The regulation describes terms and conditions for various shippers who wish to access various transporters to transport the gas of shipper from any entry point (s) to any exit point (s). The Transporter is supposed to allocate pipeline on common carrier / contract carrier basis to various shippers on non-discriminatory basis. Penalty limits for not maintaining pipeline system discipline have also been stipulated by the regulator in this regulation.

3. **Affiliate Code of Conduct for Entities Engaged in Marketing & Transportation of Natural gas**
   This Regulation defines the boundary between gas marketing activities and transportation activities by any entity who is engaged in both activities. The main objectives of the Code are as under:

   - To segregate costs associated with marketing & transportation activities
   - To make transporter to treat non-discriminately with different shippers including its own marketing activities while allocating transportation capacities
   - Development of fair & competitive natural gas market.

4. **Determination of Pipeline Tariff for Natural Gas Pipelines**
   The regulation defines the principles of determination of transportation tariff on reasonable return basis for Common/ Contract Carrier pipelines for which authorization has been given by Govt./ Regulator. Dedicated pipelines don't come under this regulation

   Various salient features of the regulation are as under:

   - Pipeline tariff (Rs/MMBtu) is determined based on Discounted Cash Flow (DCF) methodology with reasonable rate of return @ 12 % post-tax applied on total capital employed
   - Tariff review after every five consecutive years by the Board
   - The regulation lays down the principles for regarding Fixed cost, Operating cost and utilization factor for pipeline capacity to be considered for calculation of transportation tariff.
   - The pipeline is divided into various tariff zones of 300 kms length and corridor along pipeline with a width of up to 10% of the total length of pipeline (without including the length of the spur lines) or 50 Kms on both sides whichever is less. Tariff from the same source shall be uniform for all customers located within same tariff zone
   - Entity to submit for Board's approval, calculations in respect of apportioning of unit tariff over all tariff zones
   - Initial unit tariff to be determined by PNGRB on provisional basis first. Final tariff to be determined based on final audited accounts. Adjustment between provisional tariff and final tariff is done on retrospective basis.

5. **Declaration of Natural Gas Pipeline as Common Carrier or Contract carrier**
   The main objectives of this regulation are development of competitive natural gas markets and to avoid over investment by optimum utilization of infrastructure. The regulation describes the procedure for declaring the existing pipeline as common/contract carrier.

   - Contract Carrier is capacity over entity's own requirement available to any other entity subject to the latter entering into a firm contract for a period of minimum of one year
   - Common Carrier is capacity over entity's own requirement and allocated on a contract carrier basis shall be available to any other entity subject to the latter entering into a contract normally for a period of less than one year,provided that if the common carrier capacity is not fully utilized, the entity may contract the same for a period of one year or more

- If extra capacity to be provided on common carrier basis <33 % of (Entity requirement+ Firm contracted capacity), capacity will be made available on expiry of firm contract/by way of expansion.
- When extra capacity to be provided on common carrier basis <10 % of (Entity requirement + Firm contracted capacity), the Board may on a suo motu basis require an entity to build extra capacity.

6. **Determination Capacity of Petroleum, Petroleum Products and Natural Gas Pipelines**
   The regulation defines the procedure, parameters (constant & variable) and frequency of declaration of pipeline capacity in MMSCMD for natural gas by the entity. Capacity determination is based on selected Software Package & Flow Equation approved by Board

   The capacity determined is to be used for the following:

   - Declaring pipeline as Common/ Contract Carrier
   - Tariff Determination
   - For providing access to available capacity on non discriminatory basis

PNGRB Regulations for CGD Sector

1. Determination of Network Tariff: dated 19.03.2008(GSR – 197 E):
   - Based on DCF
   - Return of Capital @ 14% post tax.
   - 4 amendments - (i) Dt. 19.11.2008, (ii) Dt. 07.06.2010, (iii) Dt. 21.03.2012, (iv) Dt. 01.01.2015
2. Exclusivity for City Gas or local nature Gas distribution: GSR – 198(E) dated 19/03/2008
   - Provided exclusivity (for 5 years) from the purview of Contract / Common Carrier.
   - If operation is already 'on' but less than 3 years, then 5 years from issue of letter by PNGRB and if it more than 3 years, then 3 years from issue of letter.
   - Specific Performance Bond: For entities approved by Central Government prior to these regulations.
3. **Service Obligations:**
   - Provide PNG connections as per authorization
   - Meet Targets of inch-Km of steel pipelines
   - To supply gas pipeline upto 25 metres from the metering point on the tap off
   - To enter into separate contract for compressors etc and take delivery of CNG Ex-On-line Compressor Station on Trunk / Spur pipelines
   - Post exclusivity period, other entities could use CGD network for their requirement. In such a case, the Licensee is to allow 'third Party Access' on Non – discriminatory basis on per "Access Code for CGD" and Regulation for "Declaring CGD network on Common Carrier/ Contract Carrier.

     Two amendments dated 09-07-2010 and 01-01-2015 have been introduced.

4. **Authorising Entities to lay,build, operate or expand City / local Gas (19-03-2008)**
   - Defines Geographic Area (GA) or any other contagious area.
   - Defines CGD network, PNG and CNG.
   - Minimum work Programme.
   - Transportation rate for CGD in Rs/ MMBTU.
   - Transportation rate for CNG in Rs / Kg for online compression of CNG.
   - Work programme – Time bound for No. of domestic PNG connections, no of CNG stations and inch-Km of steel pipeline.
5. **Tech Standards and Specifications including safety standards for City Gas Distributors – 2008**
   These regulations cover design, materials, inspection & testing, O&M and safety of the CGD network. It lays out the standards and the Schedules outline all the above aspects in detail.
6. **Regulation for quality of service 2008**
   These regulations complements the Regulation per Authorizing entities for laying, Building and operating pipeline as regards their servicing obligation. It details all aspects related to customer's dealings as regards applications, feedback, metering, billing complaints etc.
7. **Regulations for Access Code for CGD-2001**
   - Post exclusivity period, applicable as a Contract/ Common Carrier.
   - Capacity declaration at all entry/ exit – 270 days and then on monthly basis for all/ any shipper.
8. **Regulations for Integrity Management for CGD/local Gas Distributor network – 2013**
   - To improve confidence in safety etc.
   - For evaluating risk with CGD activate and allocating resources for prevention, detection mitigation.
   - Improve safety of CGD network so as to protect personnel, property and environment.
   - More streamlined and effective operations.
9. **Regulation for Determining capacity of City or local Gas Distribution – 2015:**
   - Defines the network capacity of the steel network in steady state condition.
   - The CGD capability of the MDPE (Medium Density Poly Ethylene) network.
   - Capacity assessment group is formed.
   - The constant parameters like Int. Diameter, length,Roughness, efficiency factors, velocity (max 30 m/sec), standard Temperature, pressure.
   - The variable permanent like operating Temperature, inlet temperature, outlet temperature, inlet and outlet pressure,Maximum operating pressure, Minimum operating pressure, elevation difference, Gas Composition etc.
   - A suitable software package to be taken / used by the entity.
   - If CGS capacity in less than the steel network, the lower of the two would be selected as declared capacity.
   - QR (Technical) has been defined for project execution and operation of CGD.
   - Financial QR in terms of minimum Networth commensurate with the population in the geographical Area as for census – 2011.
   - Credible Plan for souring natural Gas.
   - Bidding criteria and their weightage.
   - Escalation rates and indexation defined.

- Provision for Performance Bond
- Provision for renunciation of authorization in favour of another entity.
- Natural Gas tie up (GSA) with sulphur in 180 days
- Minimum: 5 SCM/ Month – PNG Customer
- 75,000 SCM/ Month – CNG station
- Financial closure for 90% of Project cost in 270 days
- Exclusivity for 8 years and can be extended by 2 years of the entity achieves the Min. Work Program.
- Service obligation defined as regards metering and safety requirement
- Force Majeures defined along with recourse and relaxations.
- Basis for GA:- (a) Gas availability & defined connectivity, b) Geographical contiguity

Annexure III

New Domestic Natural Gas Pricing Guidelines, 2014

No.22013/27/2012ONG D.V.—In supersession of this Ministry's Gazette notification no. 22011/3/2012ONG. D.V dated 10.1.2014, the Government of India hereby notifies the New Domestic Natural Gas Pricing Guidelines, 2014, as hereunder:—

1. The wellhead gas price* (P), under these guidelines would be determined as per the formula given below:

$$P = \frac{V_{HH}P_{HH} + V_{AC}P_{AC} + V_{NBP}P_{NBP} + V_{R}P_{R}}{V_{HH} + V_{AC} + V_{NBP} + _{VR}}$$

Where

(i) V_{HH} = Total annual volume of natural gas consumed in USA & Mexico.

(ii) V_{AC} = Total annual volume of natural gas consumed in Canada.

(iii) V_{NBP} = Total annual volume of natural gas consumed in European Union (EU) and Former Soviet Union (FSU) countries, excluding Russia.

(iv) V_{R} = Total annual volume of natural gas consumed in Russia.

(v) P_{HH} and P_{NBP} are the annual average of daily prices at Henry Hub (HH) and National Balancing Point (NBP) respectively, less the transportation and treatment charges as given in para 2.

(vi) PAC and PR are the annual average of monthly prices at Alberta Hub and Russia (as published by Federal Tariff of the Russian Government or equivalent source) respectively, less the transportation and treatment charges as given in para 2.

(*Well head price refers to the price of gas receivable by the producer of gas at the contract area/ lease area from the buyer of gas. In case of onland blocks, the price receivable by the contractor (producer) in the contract area will be the well head price. In case of offshore blocks, if the gas is processed and sold in the offshore contract area, the price receivable at the offshore will be the well head price. If the gas is brought to landfall point for processing and is sold at landfall point, the facilities located in the landfall point will be considered part of the contract area and the price receivable at land fall point will be the well head price).

2. The wellhead price for three different hubs and Russia would be determined by deducting US $ 0.50/ MMBTU towards transportation and treatment charges from each of the three Hub prices and Russian price.

3. The gas price, determined, under these guidelines would be applicable to all gas produced from nomination fields given to ONGC and OIL India, New Exploration and Licensing Policy (NELP) blocks, such PreNELP blocks where, the Production Sharing Contract, (PSC) provides for Government approval of gas prices and Coal Bed Methane (CBM) blocks except as indicated in para 4 and 5 below.

4. The gas price, so determined under these guidelines shall not be applicable, where prices have been fixed contractually for a certain period of time, till the end of such period. This gas price shall also not be applicable where the PSC concerned provides for a specific formula for natural gas price indexation/fixation and to such PreNELP PSCs which do not provide for Government approval of formula/basis for gas prices. Further, the pricing of natural gas from small/isolated fields in the nomination blocks of NOCs will continue to be governed by the extant guidelines in respect of these fields issued on 8th July, 2013.

5. The matter relating to cost recovery on account of shortfall in envisaged production from D1, D3 discoveries of Block KGDWN98/ 3 is under arbitration. The difference between the price, determined under these guidelines converted to NCV basis and the present price (US $ 4.2 per million BTU) would be credited to the gas pool account maintained by GAIL and whether the amount so collected

is payable or not, to the contractors of this Blocks, would be dependent on the outcome of the award of pending arbitration and any attendant legal proceedings.

6. The periodicity of price determination/notification shall be half yearly. The price and volume data used for calculation of price under these guidelines shall be the trailing four quarter data with one quarter lag. The first price on the basis of aforementioned formula in these guidelines would be determined on the basis of price prevailing at Henry Hub, NBP, Alberta Canada and Russia, between 1st July, 2013 and 30th June, 2014. This price would come into effect from 1st November, 2014 and would remain valid till 31st March, 2015. Thereafter, it would be revised for the period 1st April, 2015 to 30th September, 2015 on the basis of said prices prevalent between 1st January, 2014 and 31st December, 2014, i.e., with the lag of a quarter and so on. The price determined under these guidelines would be announced in advance of the half year, for which it is applicable.

7. The price determined under these guidelines would be applied prospectively with effect from 1st November, 2014.

8. Director General of Petroleum Planning and Analysis Cell (DG PPAC) under the Ministry of Petroleum and Natural Gas shall notify the periodic revision of prices under these guidelines.

9. For all discoveries after the issuance of these guidelines, in Ultra Deep Water Areas, Deep Water Areas and High Pressure High Temperature (well head shutin pressure > 690 bars, bottom hole temperature> 150 degree centigrade) areas, a premium would be given on the gas price determined as per the formula given in para 1. The premium under this para shall be determined as per prescribed procedure.

10. Price determined under these guidelines would be on GCV basis.

11. The price, determined under these guidelines would be in US $ per MMBTU.

12. In the North Eastern Region (NER), the 40% subsidy would continue to be available for gas supplied by ONGC/OIL. However, as private operators are also likely to start production of gas in NER, and would be operating in the same market, this subsidy would also be available to them to incentivize exploration and production.

13. The price determined under these guidelines shall be applicable to all sectors uniformly.

Annexure IV A

Completed gas pipelines as on 30.09.2019

(Source PNGRB AR 2018-19)

S. No.	Name of the Pipeline	Name of Entity	Authorized		Date of Authorization	States Through Which it Passes
			Length (km)	Capacity (MMSCMD)		
1	Assam Regional Network	GAIL (India) Limited	7.8	2.500	04.11.2009	Assam
2	Cauvery Basin Network	GAIL (India) Limited	240.3	4.330	04.11.2009	Puducherry, Tamil Nadu
3	Hazira-Vijaipur -Jagdishpur-GREP (Gas Rehabilitation and Expansion Project)-Dahej -Vijaipur HVJ/VDPL	GAIL (India) Limited	4222.0	57.300	19.04.2010	Uttar Pradesh, Madhya Pradesh, Rajasthan, Gujarat
4	Kakinada-Hyderabad -Uran-Ahmedabad (East West Pipeline)	Pipeline Infrastructure Limited	1460.0	95.000	19.04.2010	Andhra Pradesh, Gujarat, Maharashtra, Telangana
5	Dahej-Uran -Panvel-Dhabhol	GAIL (India) Limited	815.0	19.900	10.05.2010	Gujarat, Maharashtra
6	KG Basin Network	GAIL (India) Limited	877.9	16.000	12.05.2010	Andhra Pradesh, Puducherry
7	Gujarat Regional Network	GAIL (India) Limited	608.8	8.310	03.12.2010	Gujarat
8	Agartala Regional Network	GAIL (India) Limited	55.4	2.000	13.12.2010	Agartala
9	Dadri-Panipat	Indian Oil Corporation Limited	132.0	9.500	05.01.2011	Haryana, Punjab, Uttar Pradesh
10	Dahej-Vijaipur (DVPL) -Vijaipur-Dadri (GREP) Upgradation DVPL 2 & VDPL	GAIL (India) Limited	1280.0	54.000	14.02.2011	Gujarat, Madhya Pradesh, Rajasthan, Uttar Pradesh
11	Mumbai Regional Network	GAIL (India) Limited	128.7	7.000	14.03.2011	Maharashtra
12	Uran-Trombay	Oil and Natural Gas Corporation Limited	24.0	6.000	03.05.2011	Maharashtra
13	Hazira-Ankleshwar	Gujarat Gas Company Limited	73.2	5.060	05.07.2012	Gujarat
14	High Pressure Gujarat Gas Grid	Gujarat State Petronet Limited	2239.0	31.000	27.07.2012	Gujarat
15	Low Pressure Gujarat Gas Grid	Gujarat State Petronet Limited	57.6	12.000	19.03.2013	Gujarat
16	Shahdol-Phulpur	Reliance Gas Pipelines Limited	312.0	3.500	11.07.2013	Madhya Pradesh, Uttar Pradesh
17	Assam Regional Network	Assam Gas Company Limited	104.7	2.428	20.12.2013	Assam
18	Dukli Maharajganj	GAIL (India) Limited	5.2	0.260	09.01.2014	Agartala
19	Uran-Taloja	Deepak Fertilizer & Petrochemicals Corporation Limited	42.0	0.700	21.10.2014	Maharashtra
20	ONGC WHI North Penugonda -GAIL SV Station	KEI RSOS Petroleum & Energy Private Limited	7.8	0.050	16.02.2016	Andhra Pradesh
		Total	**12693.4**			

Annexure IV B

Partly Commissioned Gas Pipelines as on 30.09.2019

(Source PNGRB Annual Report 2018-19)

S. No.	Name of Pipeline	Name of Entity	Authorized		Date of Authorization	Commissioned Length (km)	Target date of Completion	States through which it passes
			Length (km)	Capacity (MMSCMD)				
1	Chhainsa -Jhajjar -Hissar	GAIL (India) Limited	455.0	35.0	13.12.2010	310.0	Sep'20	Haryana, Rajasthan, Punjab
2	Dadri -Bawana -Nangal	GAIL (India) Limited	886.0	31.0	15.02.2011	816.0	Aug'20	Punjab, Haryana, Uttar Pradesh, Uttarakhand, Delhi
3	Kochi -Koottanad -Bangalore -Mangalore	GAIL (India) Limited	1104.0	16.0	31.05.2011	138.0	Feb'22	Kerala, Tamil Nadu, Karnataka, UT of Puducherry
4	Mehsana -Bhatinda	GSPL India Gasnet Limited	2052.0	77.11	07.07.2011	340.0	Mar'20	Gujarat, Rajasthan, Haryana, Punjab
5	Bhatinda -Jammu -Srinagar	GSPL India Gasnet Limited	725	42.42	07.07.2011	102.0	01.12.2017 (Request for time extension is under consideration)	Punjab, Jammu & Kashmir
6	Dabhol -Bangalore	GAIL (India) Limited	1414.0	16.0	14.11.2011	1098.0	Feb'13	Maha-rashtra, Karnataka, Goa
7	Ennore -Tuticorin	Indian Oil Corporation Limited	1385.0	84.7	10.12.2015	22.6	Feb'21	Tamilnadu, Karnataka
8	Jagdishpur Haldia Bokaro Dhamra -Barauni -Guwahati Natural Gas Pipeline	GAIL (India) Limited	3306.0	16.0	29.01.2018	850.0	Dec'20 (Feb'21 for Barauni -Guwahati Section)	Uttar Pradesh, Bihar, Jharkhand, West Bengal, Odisha, Assam
			Total	**11327.0**		**3676.6**		

Abbreviations

BBINS	Bangladesh Bhutan India Nepal Sri Lanka (geographical region)
bbl/d	Barrel of oil per day
BCF/bcf	Billion cubic feet
Bcfd	Billion cubic feet per day
BCM/bcm	Billion cubic metres
BCMA	Billion cubic metres per annum
Bn/bn	Billion
BOG	Boil off gas
BPCL	Bharat Petroleum Corporation Ltd
CAGR	Compound annual growth rate
CAPEX	Capital Expenditure
CGD	City Gas Distribution
COD	Commercial Operation Date
COP	Conference of Parties (Apex body of UNFCCC)
Cr	Crores (10 millions)
CUM/cum	cubic metres
DAT	Delivered at Terminal
DES	Delivered ex-ship
DGH	Directorate General of Hydrocarbons (India)
DWT	Dead weight tons
E&P	Exploration and Production (for oil & gas)
EIA	Environment Impact Study
EIA	Energy Information Administration (Parent : United States Department of Energy)
EPC	Engineering, Procurement and Construction
EU	European Union
EV	Electric Vehicles (Battery driven)
FEED	Front end engineering design
FERC	Federal Energy Regulatory Commission, USA
FID	Financial Investment Decision
FLNG	Floating Liquefied Natural Gas
FSRU	Floating Storage and Regasification Unit
GAIL	Gas Authority of India Ltd
GCV	Gross Calorific Value
GDP	Gross Domestic Product
GHG	Green House Gas
GIIGNL	Internation Group of Liquefied Natural Gas Importers
GIIP	Gas Initial in Place
GOG	Gas-on-Gas
GOM	Gulf of Mexico (geographical region)
GSMP	Gas Sector Master Plan (Bangladesh)
GSPC	Gujarat State Petroleum Corporation
GSPC	Gujarat State Petroleum Corporation Ltd
GSPL	Gujarat State Petronet Ltd
GW	Giga watts

HELP	Hydrocarbons Exploration Licencing Policy (India)
IGU	International Gas Union
IMO	International Maritime Organization
INDC	Intended Nationally Determined Contributions
IOC	International Oil Companies
IOCL	Indian Oil Corporation Ltd
IPB	India-Pakistan-Bangladesh (geographical region)
IPP	Import Price Parity
IRR	Internal rate of return
JICA	Japan International Cooperation Agency
JKM	Japan Korea Marker
JKTM	Japan Korea Taiwan China (geographical region)
KW/kw	Kilo Watts
KWHR/kwhr	Kilowatt Hours (of electrical energy)
LNG	Liquefied Natural Gas
LTGEP	Long-term Generation Expansion Plan
LTGEP	Long term generation expansion plan (Sri Lanka)
MCMD	Million standard cubic metres per day
MDO	Mine Development Operator
MMSCM	Million standard cubic metres
MMSCMD	Million standard cubic metres per day
MMT	Million Metric Tons
Mn	Million
MoP&NG	Ministry of Petroleum & Natural Gas (India)
MTPA/mtpa	Million Tons per annum
MU	Million Units (of electricity)
MW	Mega watts
NBP	National Balancing Point (in UK)
NDC	Nationally Determined Contributions
NELP	New Exploration Licencing Policy (India)
NOC	National Oil Companies
NWP	North-west Europe (geographical region)
OECD	Organization for Economic Cooperation and Development
OGV	Ocean going vessel
OIES	Oxford Institute of Energy Studies
OPEC	Organization of Petroleum Exporting Countries
OPEX	Operational Expenditure
PNGRB	Petroleum & Natural Gas Regulatory Commission (India)
PPA	Power Purchase Agreement
PSC	Production Sharing Contract
PSMP	Power Sector Master Plan
PV	Photo Voltaic
Q max	Q is for Qatar and max for maximum capacity of LNG Vessels (about 266,000 cum)
RLNG	Regasified LNG

ROE	Return on Equity
SO2	Sulfur di oxide (GAS)
SPA	Sale-Purchase Agreement
T&D	Transmission and Distribution
TCF/tcf	Trillion cubic feet
TCM/tcm	Trillion cubic metres
TPA/tpa	Tons per annum
TTF	Title Transfer Point (in Netherlands)
UNFCCC	United Nations Climate Change Framework Convention
Unit	1 kilowatt hour of electric energy
USD	United States Dollars
VGF	Viability Gap Funding (India)
VLCC	Very large crude carriers
WW II	World War II

About SARI/EI

The US Agency for International Development (USAID) initiated the South Asia Regional Initiative for Energy (SARI/E) program in the year 2000 to promote Energy Security in the South Asia region, working on three focus areas: Cross Border Energy Trade (CBET); Energy Market Formation; and Regional Clean Energy development. The program covers the eight countries in South Asia, viz. Afghanistan, Bangladesh, Bhutan, India, The Maldives, Nepal, Pakistan and Sri Lanka. The fourth and current phase of the program, called South Asia Regional Initiative for Energy Integration (SARI/EI), is aimed at advancing regional grid integration through cross border power trade. This phase is being implemented by Integrated Research and Action for Development (IRADe), leading South Asian Think Tank. SARI/EI program was recently extended to 2022 and is a key program under USAID's Asia EDGE (Enhancing Growth and Development through Energy) Initiative. In its extended phase, SARI/EI will focus on moving the region from bilateral to trilateral and multilateral power trade, and establishing the South Asia Regional Energy Market (SAREM).

About USAID

The United States Agency for International Development (USAID) is an independent government agency that provides economics, development and humanitarian assistance around the world in support of the foreign policy goals of the United States. USAID's mission is to advance broad-based economics growth, democracy, and human progress in developing countries and emerging economies. To do so, it is partnering with governments and other actors, making innovative use of science, technology, and human capital to bring the profound results to a greatest number of people.

About IRADe

IRADe, located in Delhi, is a non-profit and fully autonomous institute for advance research. IRADe's multidisciplinary research and policy analysis aid action programs. It is a hub for a network of diverse stakeholders. Established in 2002, the institute is recognized as an R&D organization by the Department of Scientific and Industrial Research and Ministry of Science and Technology of the Government of India. The Ministry of Urban Development has accorded IRADe the status of Centre of Excellence for Urban Development and Climate Change. Through the SARI/EI program, IRADe is pushing the envelope for sustainable energy access through experts and members from South Asia.

For more information, please visit the SARI/EI project website:

Website: https: //sari-energy.org/

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